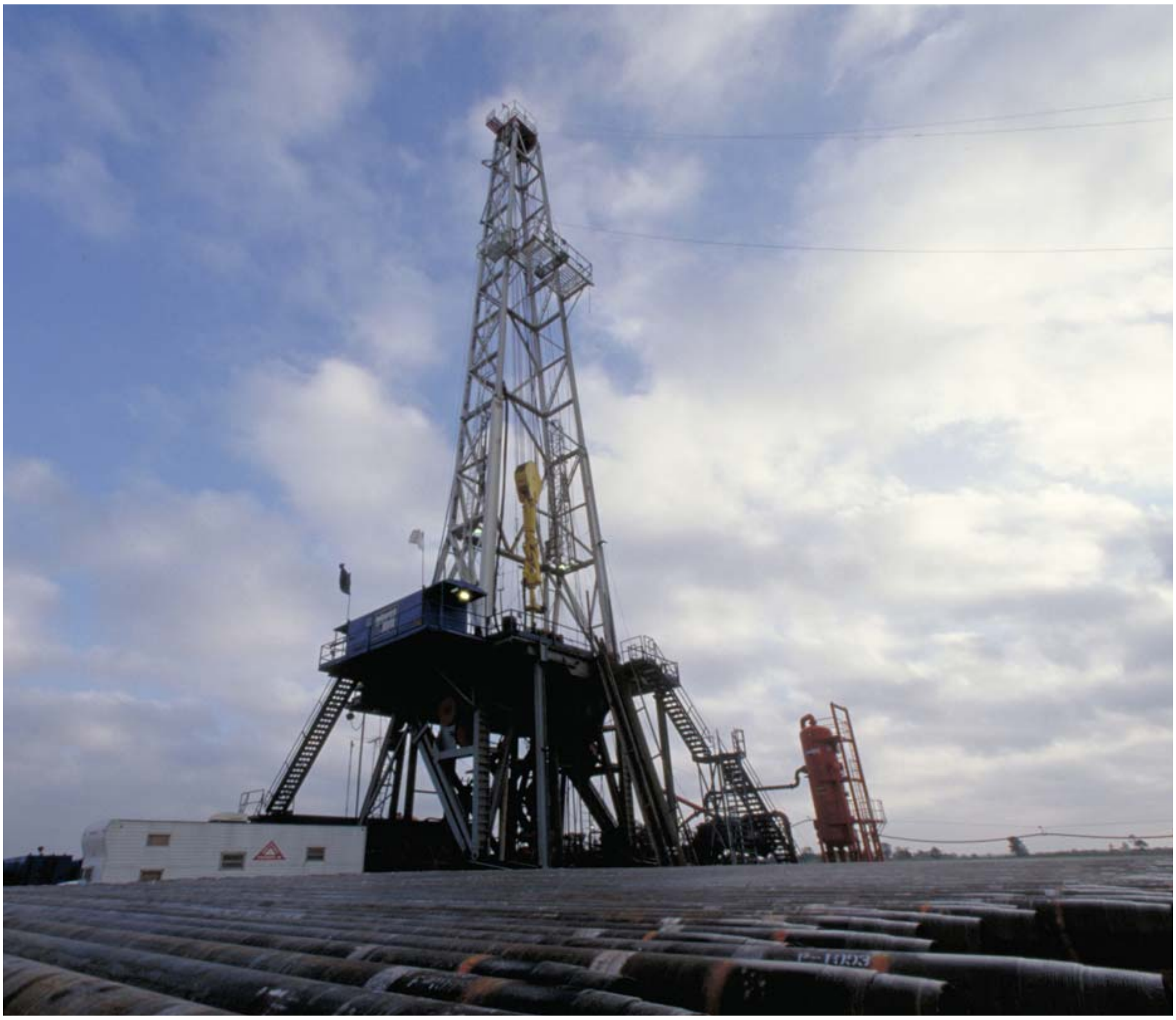
# *Towards a Petroleum Sector Master Plan for Kenya*



# Acknowledgements

This Study was developed for the Government of Kenya, Ministry of Energy and Petroleum to provide a supporting document which will allow the Government to develop its own Petroleum Sector Master Plan for the Country, taking into account regional development in oil and gas. The PwC Consortium was contracted by the World Bank to carry out this Study. The Team included PwC staff from offices in Kenya and India, sub-consultants Channoil Consulting and QED Gas, Professor Jacob Kibwage for his specific focus on the environmental and social concerns and other independent consultants for the policy and legislation review.

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# *Executive Summary*

# 1. Executive Summary

## 1.1. Introduction and Background

### 1.1.1. Introduction

The World Bank appointed PricewaterhouseCoopers and its consortium partners consisting of Channoil Consulting Limited and QED Gas Consulting ("PwC Consortium") to undertake this consultancy with the primary objective of this Final Report to support the Government of Kenya (GoK) towards the development of a Petroleum Sector Master Plan for Kenya. The key points to be covered during the work included:

- Current status of the oil and gas supply situation and market in Kenya
- Future projections of oil and gas supply and demand up to 2040
- Identification of the key decisions and steps to be taken in the development of the sector:
    - Legal and regulatory framework
    - Energy policy
    - Infrastructure requirements
    - Economics, markets and pricing

The work has taken just over a year to complete and included extensive stakeholder consultations and liaison through a Steering Committee drawn from key sector institutions.

In writing this Final Report, we have divided the material into the following sections:

- Current Status of the Kenyan Oil & Gas Sector
- Upstream Oil & Gas Sector
- Towards the Master Plan – Oil Sector
- Towards the Master Plan – Gas Sector
- Towards the Master Plan – Financing Issues
- Towards the Master Plan – Environmental and Social Issues
- Conclusions and Recommendations

Whilst we have tried to ensure that the main body of the Report includes all of the assumptions used and rationale applied in reaching our conclusions and recommendations, we have nevertheless attached further background data and information in the Appendices.

### 1.1.1. Purpose of this report

The purpose of this report is to support the GoK in the development of its Petroleum Master Plan (PMP), which integrates all elements of the oil and gas value chains - from exploration, production, transport, processing, storage and distribution, and usage in domestic and export markets. In this report we presents strategic alternatives, recommendations and decision hierarchies that will be considered by the GoK to catalyse the development of the oil and gas sector and maximize value arising from oil and natural gas development in Kenya.

The expected higher-level outcome is that the GoK formulates a vision for the development of its petroleum sector and makes policy and investment decisions at earliest possible opportunity to maximize the value from its oil and natural gas resources and to stimulate investments in the domestic market.

It should be noted that Master Planning is a continuous process and plans evolve as more information becomes available on potential supply, demand, resulting infrastructure requirements and other factors. Hence, this report will not be a complete technical plan for petroleum sector development; rather, it will provide recommendations for a detailed roadmap for strategic, policy and institutional decisions upon which investments can be designed and implemented in a fully coordinated manner to move towards a vision for the sector. Based on this report and recognizing uncertainties that are expected to reduce over time, the GoK will develop its own Petroleum Sector Master Plan and continue to update it at regular intervals into the future.

### *1.1.2. Background*

Oil exploration in Kenya began in 1954 before Kenya's Independence, after which upstream activities continued in varying intensities with a number of dry wells being drilled. In 2012, Tullow Oil announced the discovery of an oil potential of 300 million barrels of oil in Turkana rekindling Kenya's prospects of becoming an oil producing nation. So far seven discoveries have been made and Tullow Oil estimates the resource potential at over 600 million barrels of oil, with the possibility that it will exceed 2 billion barrels of oil. Unrisked gas discoveries have also been reported in Coastal/Offshore Lamu and onshore in the Anza Graben.

Kenya's neighbouring countries are more advanced in their oil and gas activities with Uganda having discovered oil in 2006, and now entering the development phase, while South Sudan has been producing crude oil for several years.

On the economic front, Kenya has witnessed strong growth following the downturn experienced in 2008/09 due to the effects of post- election violence, drought and spill-offs from the global financial crisis. Real GDP growth averaged at 6.5% between 2010 and 2014 and is projected to grow at 6.2% in 2015. The long term economic outlook is for annual GDP growth of c.6.6%. Economic growth has led to the development of a downstream oil industry that has functioned independently from any upstream prospects- being mainly serviced by imported products. Discovery of significant hydrocarbons to take Kenya to an oil producing nation will require the alignment of an established downstream sector to a new upstream sector.

In addition to a fairly established downstream oil sector, growth in the economy has also led to increasing demand for power driven by a growing population, an established and growing manufacturing industry, and increasing urbanisation. With prospects for indigenous gas and its potential role in the power sector, major gas finds could steer how the power sector evolves in the medium and long term calling for careful planning of how this is actualized.

Consideration of these issues requires synchronised planning for the petroleum sector in a Master Plan to guide the Government's decision on policies, regulations and actions in the sector

### *1.1.3. Vision 2030, infrastructure needs, and the funding gap*

Kenya prides itself in having successfully established its economy as the largest in East Africa. As of 2013, Kenya accounted for 41% of total GDP in the East African Community with Tanzania and Uganda contributing 30% and 20% respectively. Private sector participation in key industries such as telecommunications and energy in parallel to the liberalisation of trade have driven growth of the Kenya's middle class and attracted FDI. The last decade has represented the longest sustained period of continued growth for the economy, being represented by the Government of Kenya's Vision 2030 initiative to transform the economy from a low income country to a middle income country through the identification and investment in flagship development projects across the Nation.

Despite the obvious potential of the Kenyan economy for significant economic growth (being largely supported by the thriving services sectors and fairly developed human capital); the economy is still hampered by relatively undeveloped infrastructure. In addressing these development gaps, the Government of Kenya initiated its 30 year economic development plan – Kenya Vision 2030.

*High-level summary of Kenya's achievement of Vision 2030*

***The Vision: -*** A national long-term development blue-print to create a globally competitive and prosperous nation with a high quality of life by 2030, that aims to transform Kenya into a newly industrializing, middle-income country providing a high quality of life to all its citizens by 2030 in a clean and secure environment.

The vision is anchored on three key pillars; economic, social and political governance.

*- Kenya Vision2030 (http://www.vision2030.go.ke/index.php/vision)*

**The Government of Kenya launched Vision2030 in 2008, with the objective of executing the projects over 5 year medium term rolling plans.**

| Project Name | Project Description | Development Progress |
|---|---|---|
| **Commuter Rail Network** | Railway stations in Syokimau, Imara Daima, Makadara, Jomo Kenyatta International Airport ("JKIA") link, and Nairobi Central Railway Station | On Schedule<br><br>Syokimau, Makadara and Imara Daima stations all successfully opened. 2014 GoK budget allocated funds for construction of JKIA link |
| **Dredging of Mombasa Port** | Dredging of 15m deep Berth 19 to allow vessels of up to 250 meters to unload containers | Completed |
| **Energy Generation of 23,000 MW and Distribution** | Increase national power generation – through promotion of private sector participation and the use of clean energy | Commenced, guided by LCPDP and 5000+ MW by 2017 plan |
| **Airport Expansion and Modernisation** | Upgrade the Jomo Kenyatta International airport with a new terminal to allow c. 20 million passengers annually and increase airline fleet capacity | Commenced |
| **Lamu Port and New Transport Corridor Development to Southern Sudan and Ethiopia ("LAPSSET")** | • Lamu Port: 20 Berths<br>• Railway: 1,710km<br>• Highway: 880km<br>• Pipeline: crude oil and product<br>• Resort City: 3 lots<br>• Airport: 3 lots<br>• Oil Refinery: 120,000 bpd | MoU signed between Government of Kenya, Ethiopia and Sudan<br><br>Development of three berths at the port of Lamu has begun. Oil pipeline routing increases the opportunities within the LAPSSET corridor.<br><br>The Isiolo-Marsabit-Moyale road spanning 507km is nearing completion. |
| **Road Network Expansion** | Country wide road expansion through the upgrading of old roads and development / expansion of new roads | Nairobi – Thika complete<br><br>Other road networks near completion<br><br>A new roads programme has been launched by the Jubilee Government |

*Source: Vision2030.go.ke*

The planned investments in the infrastructure projects above are projected to strain already limited Government finances. For the 2014/15 financial year the total Government budget (national and counties) was

KES 1,840b (US$ 20.63b).[1] According to the March 2010 Africa Infrastructure Country Diagnostic (AICD) report on Kenya, the infrastructure funding gap is estimated at US$ 2.1b per year.

In the case of the oil and gas sector, the successful completion of the planned ports, airports, and railway investments under LAPSSET will be key to enable the development of the sector, given the capacity constraints of Kenya's existing infrastructure and the geographic location of the oil and gas prospects. The March 2010 AICD report identified a road maintenance backlog and fragmentary infrastructure coverage in the northern half of Kenya as key challenges. The LAPSSET project and others such as the planned road annuity program have been conceived, in part, as a solution to these challenges.

In addition to the necessary sector-specific investments in crude and product pipelines and spur lines, gas pipelines, storage infrastructure, and downstream gas activities (whether LNG export, power generation, ammonia or methanol production), investments in supporting infrastructure like roads, airports and ICT will be required.

[1] Office of the Controller of Budget, Kenya

*Medium term expenditure estimates for Kenya (2011/12 – 2015/16)*

| | | | | | | | | | % SHARE OF TOTAL EXPENDITURE | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SECTOR | | ESTIMATES 2013/14 | REVISED BASELINE 2013/14 | BROP CEILING 2014/15 | BPS CEILING 2014/15 | PROJECTIONS 2015/16 | PROJECTIONS 2016/17 | % Change 2013/14 - 2014/15 | ESTIMATES 2013/14 | REVISED BASELINE 2013/14 | BROP CEILING 2014/15 | BPS CEILING 2014/15 | PROJECTIONS 2015/16 | PROJECTIONS 2016/17 |
| AGRICULTURE, RURAL & URBAN DEVELOPMENT | SUB-TOTAL | 53,343.4 | 64,637.8 | 55,674.9 | 55,559.1 | 64,974.5 | 66,966.1 | 4.2% | 5.0% | 5.8% | 5.0% | 5.0% | 5.4% | 5.3% |
| | Rec. Gross | 15,022.2 | 17,216.5 | 16,080.7 | 15,964.9 | 17,514.1 | 18,417.3 | 6.3% | 1.4% | 1.5% | 1.4% | 1.4% | 1.5% | 1.5% |
| | Dev. Gross | 38,321.2 | 47,421.3 | 39,594.2 | 39,594.2 | 47,460.4 | 48,548.8 | 3.3% | 3.6% | 4.3% | 3.5% | 3.6% | 4.0% | 3.9% |
| | | | | | | | | | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| ENERGY, INFRASTRUCTURE AND ICT | SUB-TOTAL | 216,531.9 | 213,158.1 | 241,908.1 | 250,047.6 | 280,085.5 | 312,439.2 | 15.5% | 20.5% | 19.1% | 21.7% | 22.5% | 23.4% | 24.8% |
| | Rec. Gross | 27,533.6 | 36,700.4 | 41,606.7 | 41,439.9 | 44,212.1 | 46,422.8 | 50.5% | 2.6% | 3.3% | 3.7% | 3.7% | 3.7% | 3.7% |
| | Dev. Gross | 188,998.4 | 176,457.7 | 200,301.4 | 208,607.7 | 235,873.4 | 266,016.5 | 10.4% | 17.9% | 15.8% | 17.9% | 18.8% | 19.7% | 21.1% |
| | | | | | | | | | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| GENERAL ECONOMIC AND COMMERCIAL AFFAIRS | SUB-TOTAL | 12,930.2 | 12,338.2 | 14,243.4 | 13,815.0 | 14,610.8 | 14,868.7 | 6.8% | 1.2% | 1.1% | 1.3% | 1.2% | 1.2% | 1.2% |
| | Rec. Gross | 7,941.4 | 7,885.1 | 8,810.2 | 8,381.7 | 8,895.2 | 9,016.4 | 5.5% | 0.8% | 0.7% | 0.8% | 0.8% | 0.7% | 0.7% |
| | Dev. Gross | 4,988.7 | 4,453.1 | 5,433.2 | 5,433.2 | 5,715.6 | 5,852.3 | 8.9% | 0.5% | 0.4% | 0.5% | 0.5% | 0.5% | 0.5% |
| | | | | | | | | | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| HEALTH | SUB-TOTAL | 36,218.1 | 46,754.6 | 37,900.6 | 37,923.2 | 40,522.6 | 43,430.0 | 4.7% | 3.4% | 4.2% | 3.4% | 3.4% | 3.4% | 3.4% |
| | Rec. Gross | 20,324.7 | 22,622.3 | 23,432.0 | 23,454.5 | 25,946.1 | 28,743.4 | 15.4% | 1.9% | 2.0% | 2.1% | 2.1% | 2.2% | 2.3% |
| | Dev. Gross | 15,893.4 | 24,132.2 | 14,468.6 | 14,468.6 | 14,576.5 | 14,686.6 | -9.0% | 1.5% | 2.2% | 1.3% | 1.3% | 1.2% | 1.2% |
| | | | | | | | | | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| EDUCATION | SUB-TOTAL | 276,242.5 | 298,158.3 | 303,150.7 | 295,971.9 | 316,799.0 | 327,787.4 | 7.1% | 26.1% | 26.8% | 27.1% | 26.6% | 26.5% | 26.0% |
| | Rec. Gross | 245,827.7 | 266,928.0 | 268,538.6 | 261,359.8 | 281,447.7 | 291,990.6 | 6.3% | 23.3% | 24.0% | 24.0% | 23.5% | 23.5% | 23.2% |
| | Dev. Gross | 30,414.7 | 31,230.3 | 34,612.2 | 34,612.2 | 35,351.3 | 35,796.7 | 13.8% | 2.9% | 2.8% | 3.1% | 3.1% | 3.0% | 2.8% |
| | | | | | | | | | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| GOVERNANCE, JUSTICE, LAW AND ORDER | SUB-TOTAL | 126,151.8 | 126,671.1 | 135,065.8 | 133,205.5 | 140,967.3 | 149,203.9 | 5.6% | 11.9% | 11.4% | 12.1% | 12.0% | 11.8% | 11.8% |
| | Rec. Gross | 111,263.6 | 117,075.2 | 120,750.7 | 118,890.4 | 126,341.4 | 134,308.4 | 6.9% | 10.5% | 10.5% | 10.8% | 10.7% | 10.6% | 10.7% |
| | Dev. Gross | 14,888.2 | 9,595.9 | 14,315.1 | 14,315.1 | 14,625.9 | 14,895.5 | -3.8% | 1.4% | 0.9% | 1.3% | 1.3% | 1.2% | 1.2% |
| | | | | | | | | | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| PUBLIC ADMINISTRATION AND INTERNATIONAL RELATIONS | SUB-TOTAL | 173,454.5 | 183,495.2 | 172,643.6 | 168,030.2 | 177,641.9 | 182,789.7 | -3.1% | 16.4% | 16.5% | 15.5% | 15.1% | 14.8% | 14.5% |
| | Rec. Gross | 73,855.4 | 80,409.9 | 81,490.1 | 76,876.8 | 83,342.0 | 85,853.3 | 4.1% | 7.0% | 7.2% | 7.3% | 6.9% | 7.0% | 6.8% |
| | Dev. Gross | 99,599.1 | 103,085.3 | 91,153.5 | 91,153.5 | 94,299.8 | 96,936.3 | -8.5% | 9.4% | 9.3% | 8.2% | 8.2% | 7.9% | 7.7% |
| | | | | | | | | | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| NATIONAL SECURITY | SUB-TOTAL | 84,723.2 | 89,029.0 | 80,300.0 | 80,070.9 | 81,102.1 | 81,912.9 | -5.5% | 8.0% | 8.0% | 7.2% | 7.2% | 6.8% | 6.5% |
| | Rec. Gross | 84,723.2 | 89,029.0 | 80,300.0 | 80,070.9 | 81,102.1 | 81,912.9 | -5.5% | 8.0% | 8.0% | 7.2% | 7.2% | 6.8% | 6.5% |
| | Dev. Gross | - | - | - | - | - | - | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | | | | | | | | | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| SOCIAL PROTECTION, CULTURE AND RECREATION | SUB-TOTAL | 20,542.8 | 20,209.4 | 21,001.5 | 21,265.1 | 21,792.9 | 22,596.9 | 3.5% | 1.9% | 1.8% | 1.9% | 1.9% | 1.8% | 1.8% |
| | Rec. Gross | 10,893.2 | 11,189.2 | 10,972.5 | 11,236.1 | 11,054.0 | 11,137.5 | 3.1% | 1.0% | 1.0% | 1.0% | 1.0% | 0.9% | 0.9% |
| | Dev. Gross | 9,649.7 | 9,020.3 | 10,028.9 | 10,028.9 | 10,738.9 | 11,459.4 | 3.9% | 0.9% | 0.8% | 0.9% | 0.9% | 0.9% | 0.9% |
| | | | | | | | | | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| ENVIRONMENT PROTECTION, WATER AND NATURAL RESOURCES | SUB-TOTAL | 57,133.5 | 59,483.1 | 55,278.9 | 54,990.8 | 57,795.2 | 58,979.1 | -3.8% | 5.4% | 5.3% | 4.9% | 5.0% | 4.8% | 4.7% |
| | Rec. Gross | 13,200.2 | 14,215.4 | 14,936.6 | 14,648.5 | 14,888.0 | 15,769.0 | 11.0% | 1.2% | 1.3% | 1.3% | 1.3% | 1.2% | 1.3% |
| | Dev. Gross | 43,933.4 | 45,267.7 | 40,342.3 | 40,342.3 | 42,907.2 | 43,210.2 | -8.2% | 4.2% | 4.1% | 3.6% | 3.6% | 3.6% | 3.4% |
| | | | | | | | | | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| TOTAL | TOTAL | 1,057,271.9 | 1,113,934.8 | 1,117,167.5 | 1,110,879.3 | 1,196,291.8 | 1,260,973.9 | 5.1% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| | Rec. Gross | 610,585.3 | 663,271.0 | 666,918.0 | 652,323.5 | 694,742.8 | 723,571.5 | 6.8% | 57.8% | 59.5% | 59.7% | 58.7% | 58.1% | 57.4% |
| | Dev. Gross | 446,686.7 | 450,663.9 | 450,249.5 | 458,555.8 | 501,549.0 | 537,402.4 | 2.7% | 42.2% | 40.5% | 40.3% | 41.3% | 41.9% | 42.6% |

*Source: Republic of Kenya, Medium Term Budget Policy Statement, February 2014*

According to IMF's World Economic Outlook 2014, GoK's revenue in 2013 was KES 934.7b (US$ 10.22b, 19.7% of GDP) against Government expenditure of KES 1,205b (US$ 13.51b, 25.4% of GDP), resulting in a deficit of KES 270b (US$ 3.02b). In the same year, GoK's net debt was KES 1,832b (US$ 20.54b) or 38.7% of GDP. In the period to 2018 (during which major infrastructure like the crude oil pipeline will need to be constructed) the IMF forecasts GoK's net debt growing to KES 3,779b (US$ 42.38b, 42.3% of 2018 forecasted GDP). Considering that GoK's net debt is forecast to double in nominal terms between 2013 and 2018, and that the crude oil export pipeline alone will cost a minimum of US$ 3.5b (KES 312b, or 17% of GoK's 2013 net debt), it is clear that development of the oil and gas sector's infrastructure will need to strongly consider private sector investment.

## 1.2. Discussion on Critical Decisions

The Oil and Gas Master Plan for Kenya has to incorporate the further development of an existing downstream oil sector, with the greenfield development of the upstream (oil and gas) sector. It can be anticipated in these circumstances that the emphasis will be on decisions required for the latter as the former already has much of the necessary legal, regulatory and commercial framework required.

The critical decisions and actions to be undertaken have been grouped under the following:

1. Policy, Legislative and Regulatory Decisions
2. Upstream and Crude Oil Pipeline
3. Downstream Oil
4. Gas Sector
5. Financing Issues
6. Social and Environmental Decisions
7. Additional Studies Required

They have then been summarized into a time line to assist the GoK in his prioritization of the various projects.

### 1.2.1. Policy, Legislative and Regulatory Framework

The key actions and decisions that need to be made include:

a) Enactment of draft legislation

GoK has recognized the need for new legislation covering the oil and gas sector to be drafted and enacted to better facilitate the development of the sector. It is critical that the legislation and policies currently under review; the Draft National Energy Policy; the Draft Energy Bill, 2015; the Draft Petroleum Exploration, Development and Production Bill, 2015; the Draft Model Production Sharing Contract; and the Draft Petroleum Exploration, Development and Production (Local Content) Regulations, 2014, are enacted in time in order that the necessary investments, and subsequent decisions in the sector can take place. In addition, there is need to update and ratify the Draft Energy (Operation of Common User Petroleum Logistics Facilities) Regulations developed in 2011 to take into consideration the cross border nature of the proposed crude pipeline and any new requirements of users of existing and proposed petroleum logistics facilities.

b) Clarification of ERA and UPRA roles

The Draft Energy Bill 2015 has given the proposed Energy Regulatory Authority (currently Energy Regulatory Commission) powers to set, review and approve contracts, tariffs and charges for common user petroleum logistics facilities and petroleum products. This is a positive step as it now allows ERA to set tariffs for pipeline transportation where ERC had previously faced legal opposition. It is necessary, however, to differentiate more clearly the role of UPRA, which has also been assigned the same role by the Draft Petroleum Exploration, Development and Production Bill, 2014. To ensure greater independence in regulating these facilities, it is recommended that this role be vested in ERA.

The passing of the proposed legislation is critical in order to allow ERA in its new function to timely set tariffs for the crude pipeline to create certainty for investors. GoK - ERA must be prepared to be flexible in its approach to sector policy and regulation so as to ensure continued investment in Kenya even in more challenging market environments. Furthermore the setting of the tariff will need to consider market players and the regulatory environment of neighbouring Uganda and later on South Sudan. We recommend a tariff study is undertaken to give recommendations based on the above considerations.

c) Framework for gas investment

Building on the enactment of the various petroleum legislation mentioned the specific regulatory and commercial framework for gas investments must be made clear so that potential investors are able to analyse the risks and returns involved. For upstream investors, this will relate to the specific gas-related terms in the PSC, noting that gas field partners will not have the option to export their product (in the short-to-medium term, at least) and so will require a clear understanding of their ability to market gas within Kenya. For midstream investors (i.e. pipelines and, potentially, LNG import facilities) they will need clarity over the policy guidelines and price regulations to be applied by ERC or the proposed ERA once enacted.

d) Investment Climate

In order to continue to attract investment in the upstream sector Kenya needs to create a favourable investment climate. The new Ninth Schedule of the Income Tax Act reintroduced Capital Gains Tax (CGT) in 2014. The reintroduction of CGT imposes up to 37.5% taxation on net gains on direct and indirect sale of interests in blocks.

It is important to assess whether the introduction of CGT would be more appropriate at a later stage as some key considerations need to be made, including the early stages of Kenya's oil and gas upstream sector and the recent decline in global oil prices. The reintroduction of CGT could lead to redeployment of capital investment elsewhere. Through PSCs signed with licenced operators, the Government of Kenya will be able to earn returns from the share of profit oil and it is therefore important that an enabling environment is created in order to realize these revenues.

Beyond the review of CGT highlighted above, we would recommend that the PPP Act allows project companies the liberty to register as limited liability companies or as branches. Under the current PPP regulation, a project company has to be a limited liability company registered in Kenya. This attracts significant taxes to the company including compensating tax, particularly on the remittance of dividends paid out of untaxed profits, as well as tax risks arising out of thin capitalization in the event that the project company with predominantly foreign shareholding is largely funded through shareholder loans.

e) Compulsory Stock Policy

As the economy grows, the security of oil supply becomes more important and there is a need to impose a level of compulsory oil stocks that meets this objective whilst also being affordable. Current average stock levels, of between 5 and 15 days, are well below international norms of 60 days or more. However, the capital and financing costs associated with such a level is likely to be prohibitive. Therefore, GoK needs to decide on an appropriate level given the status of the economy and the downstream oil sector. In consideration of these factors, we suggest a gradual approach of building up from the current levels of 5 and 15 days to 40 days with location at the point of importation as well as closer to local demand. Furthermore we recommend the setting up of an industry and Government committee to develop a comprehensive Compulsory Stock Policy and a Compulsory Stock Entity to administer these operations.

f) Coherent cross-energy policy and coordination among sector players.

Whilst it is a challenge to effectively integrate a coherent policy and strategy across all parts of the energy sector when some parts are already well established (i.e. downstream oil, power generation) whereas others are in their infancy (i.e. upstream, gas), it is a prerequisite to large scale inward investment in the sector that this is done. Key areas to address are highlighted below.

There is need for greater harmony between the current plans for power sector development and the objectives with respect to the development of Kenya's potential indigenous gas resources. Ongoing plans for procurement of coal power generation plants may run the risk of exclusion of gas power plants following production of indigenous gas as there may not be sufficient demand for uptake.

In addition, plans for investment into major pipelines and refineries need to be coordinated. The LAPSSET authority has recently gone to tender for transaction advisory services for projects within the LAPSSET corridor which includes a refinery and crude oil pipeline. Such plans should proceed following consultations and consideration of the proposed policies in this Study.

A synchronizing of strategies and capital expenditure plans by key players in the sector - NOCK, KPC, KPA, KPRL, KenGen, KPLC, and LAPSSET is critical. These plans should be managed and updated accordingly by a committee with senior decision makers from the various organizations represented.

The synchronizing of strategies as described above should lead to a coordinated Energy Master Plan, and an update of the LCPDP/Power Sector Master Plan.

## 1.2.2. Upstream and Crude Oil Pipeline

In addition to the policy, legislative and regulatory issues noted above, there are a few critical areas in the upstream sector requiring urgent attention:

(i) Data on hydrocarbon resources

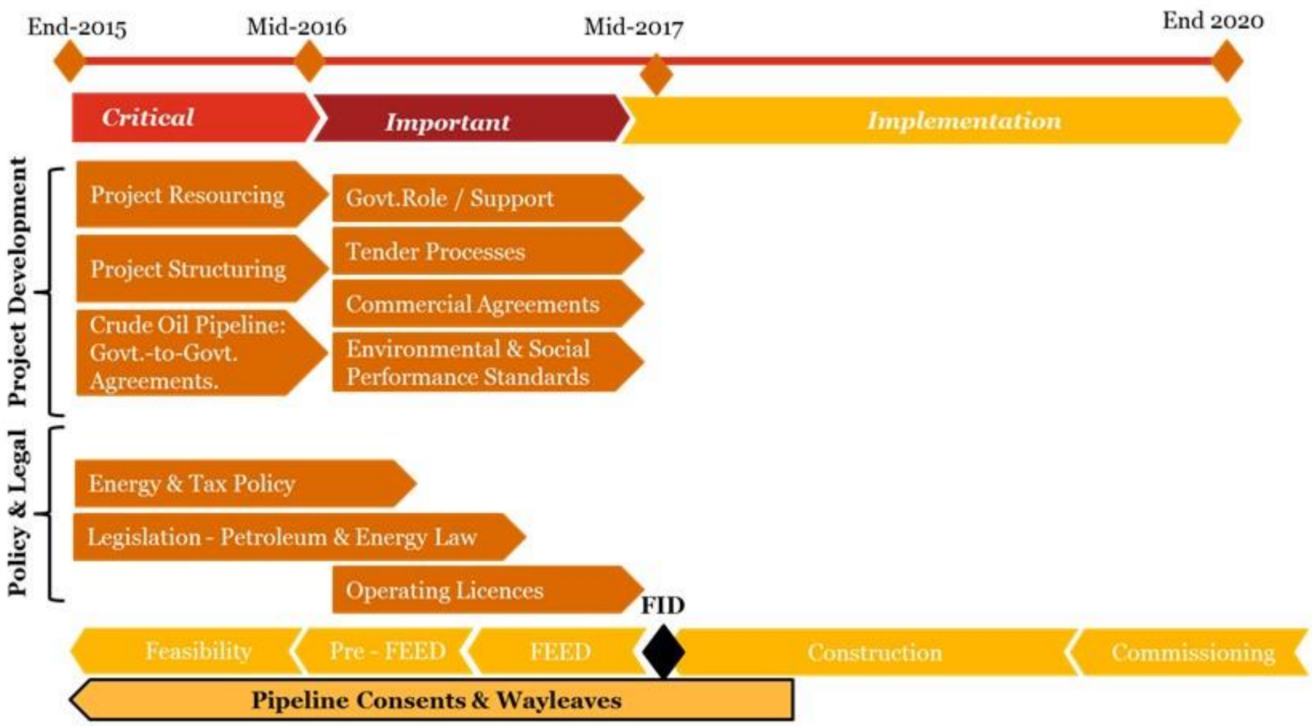
The development of an effective Oil and Gas Master Plan is hampered by the absence of reliable data as to the likely extent and recoverability of hydrocarbons in Kenya. This in turn undermines the validity of infrastructure development plans and therefore the case for further investment in the upstream sector. GoK must press licensed operators to provide updated information on the results of their seismic and drilling programs (in accordance with their licence obligations) and so consolidate the projected plans for the sector and encourage its development.

(ii) Access to Market/Crude Oil Pipeline

The promotion of upstream activities will continue if the license holders believe that there will be a market available for the hydrocarbons produced at a market price that will provide for an acceptable level of return on their investment. In addition, license holders need the comfort that the required infrastructure to evacuate the hydrocarbons produced will be in place once production begins. This means the Government needs to prioritise the timely development of the proposed crude oil export pipeline. The following decisions and steps need to be made in order to aid the development process:

a) Form the Crude Oil Pipeline Project Team who will be responsible for managing the development of the crude oil pipeline and lead on the below decision making.
b) Design and develop an ownership structure for the pipeline with consideration of the interests of key players including Government of Kenya (GoK), Government of Uganda as well as upstream players both in Kenya and Uganda. The structure needs to be both workable for the mentioned stakeholders and attractive to would be future developers and oil producers. GoK needs to clarify its position as a stakeholder of the crude pipeline in light of budgetary constraints and competing priorities. A PPP/Project Finance structure in developing the pipeline is an optimal and recommended option. Upstream players would be interested in investing in the pipeline with the primary interest of having control of effective and timely evacuation of their products. Through a PPP/Project Finance Structure, the Government would be able to ensure that technical and other risks are transferred to the private sector. Once GoK's position is clarified, the procurement of transaction advisory services needs to commence to fast track legal and commercial agreements and progress finance raising to allow for timely construction of the pipeline ready for use once production commences.
c) Kenya needs to agree a detailed bilateral agreement with the Government of Uganda on routing, capacities, responsibilities, organisation, and commercial terms on a specified timeline in order to achieve delivery of the first crude from Lake Albert and Turkana fields by 2020. GoK will then need to facilitate the consents and wayleaves process once routing is agreed upon. Once bilateral agreement and routing is agreed this then needs to be followed by a tariff setting exercise which will provide certainty of expected returns for investors. This can be done by through a consultative process with the key upstream players.

*Critical Decision Hierarchy – Getting to First Oil*




*Source: PwC Consortium*

## 1.2.3. Downstream Oil Sector

There exists within Kenya a full value chain delivering oil products to consumers. This Study's focus is therefore on how best to ensure further growth and efficient development of the sector. The key decisions and actions arising from the downstream oil sector are as follows:

a) Form the Downstream Oil Development Committee who will be responsible for managing the prioritisation of the projects, upgrading the facilities, development of efficient systems to manage product importation and distribution.

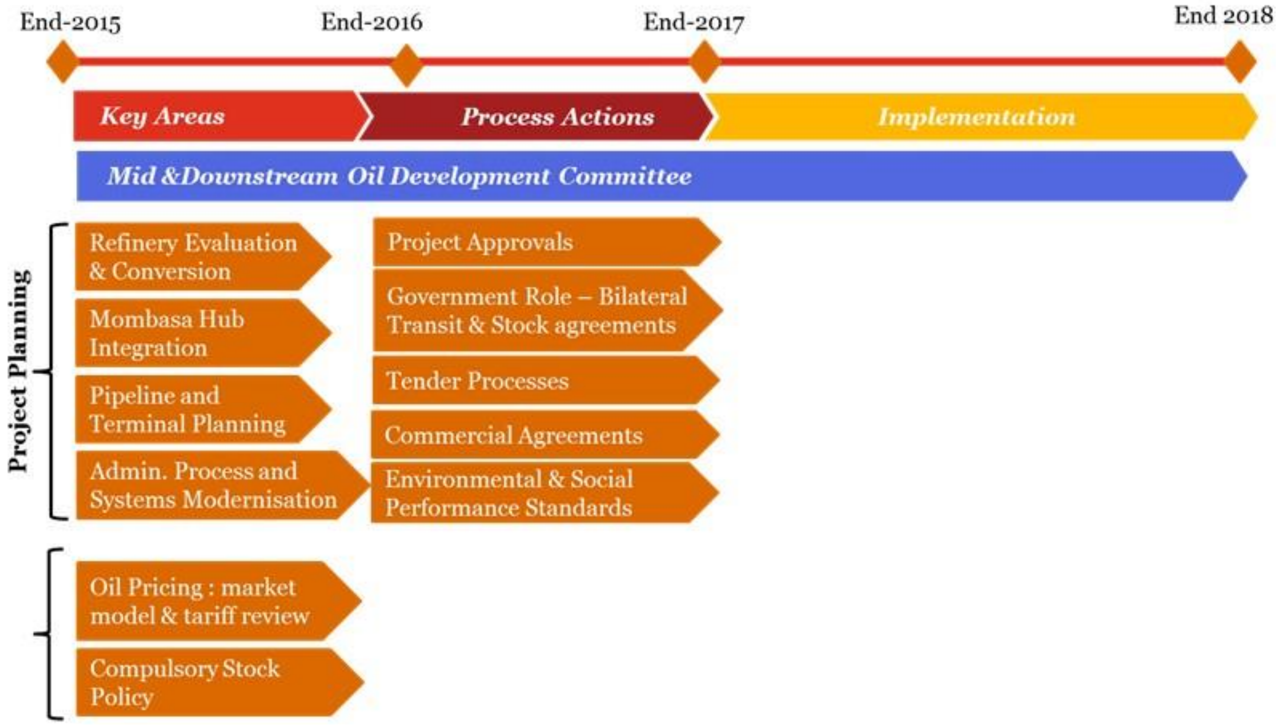
b) Forecast refining margins at KPRL are predicted to be insufficient to justify continued operations, even if the facility were upgraded and oil product imports is seen to provide a lower cost solution for the foreseeable future. Our recommendation is for the GoK and Essar to reach a conclusion on the shareholding of KPRL, following which the processing facility should be closed and the evaluation of the option of converting KPRL into an oil storage hub, and building Mombasa into an import hub considered. However, given the controversy surrounding this issue, a more detailed study may be undertaken to understand costs and economics of upgrade options.

c) In building Mombasa into an import hub there is need to network together the oil receiving, storage and handling facilities present in Mombasa and to develop a coordinated plan between the stakeholders of these facilities. There is also a need to review the current fiscal framework in order to facilitate the hub concept that would allow for trading of petroleum products within the East African Coast from Mombasa. We recommend a detailed analysis of specific requirements for converting Mombasa into an import hub, including a review of the fiscal framework.

d) Kenya Pipeline Company should lead a pipeline and terminal network planning review to take account of proposals made in this Study. The rising demand for oil products will require investments to increase storage facilities, including for LPG. These investments need to be aligned with the geographic offtake in demand and the expected timing of growth in such demand. While KPC has ongoing plans to develop such projects, the involvement of private capital and external financing should be considered.

Modernisation of the administrative processes and systems is a key step to streamline the flow of product along the oil supply chain from planned importation to final customer. It is anticipated that changes to organizational management, administrative processes, network computing, measurement and control systems will all be required to achieve leading 21st century performance.

*Critical Decision Hierarchy – Regenerating Oil Product Infrastructure*




*Source: PwC Consortium*

The decision to build a new refinery should be delayed and reviewed in more detail study taking into account the following precedent conditions; Kenyan oil demand growth to justify a world-scale refinery, the foreseen oversupply of refinery capacity in the region is more in balance; and the crude pipeline routing is agreed upon in order to firm up a preferred refinery location.

### 1.2.4. Gas Sector

With regard to natural gas resources, any prospects for accessing export markets appear remote at this stage of the sector's development and so developers will be reliant on the potential to place indigenous gas into the local market. By far the most likely demand source is power generation where gas usage offers economic as well as environmental advantages. There is no existing gas industry in Kenya and the challenge is to create an environment whereby the necessary levels of investment are more likely to take place such that this industry can be established and developed. This is a more difficult objective for natural gas than for the oil industry, for example, due to the relatively high levels of infrastructure investment required up-front in order to connect the point of supply (e.g. gas field) with the market. The key first steps and decisions to be made are as follows:

(i) Role of gas vs coal in power generation

GoK should confirm its commitment to gas as a major contributor to the nation's generating mix. This can be justified on purely economic grounds, but also due to its environmental credentials (compared to any other form of thermal power generation) and operational advantages (compared to renewables). As stated above, a comprehensive Power Sector Master Plan is an urgent requirement to guide GoK's larger power capacity expansion initiatives, as well as the development of indigenous natural gas production. Until such a study can be completed, it is important that GoK suspends the planned coal generation projects, as the commissioning of these may deny indigenous gas the domestic market it requires to attract investment in exploration and field development, while saddling Kenyan consumers with a more expensive and less clean power source.

(ii) Gas legislation

If GoK does affirm the role of gas in power generation, then a starting point for the development of the gas sector is to have a coherent energy policy that takes into account the various needs across the oil, gas, power and wider energy sector. In terms of legislation, primary legislation should include developing and passing a specific Gas Law and establishing a gas industry regulator and regulatory framework. Secondary legislation will include considering and drafting operating license agreements and designing the regulatory framework, including the development of a network code and tariff setting policies.

(iii) Gas terms in PSCs

Currently, Kenyan production licenses contemplate oil reserves and these will require adjustment in the event of significant gas finds. The Government will need to agree specific gas terms in upstream production licenses and terms for supplying gas. The economic modelling provided in this report will give a steer to negotiating gas pricing terms but project specific modelling may be required. When discussing the development of individual gas projects with developers, it will be important to consider the development of the wider industry from the onset and not encourage project development on a stand-alone basis.

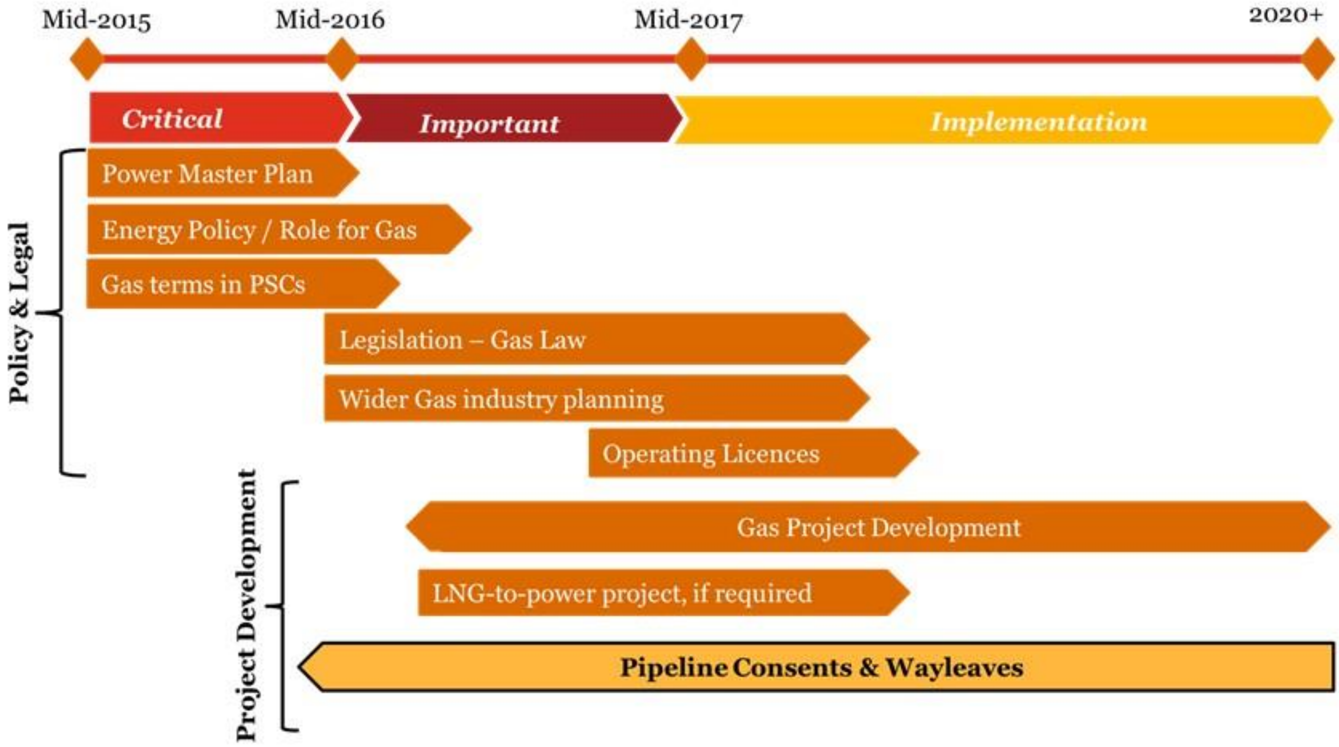
(iv) Gas project development

This needs to take into account the timing of the first gas plants to meet the power plan needs. Urgent questions remain as to whether new base load-type plants will be required in the next few years and a coherent view is required in order to ensure that new gas projects are viable and in the best interests of Kenyan consumers. Consents and wayleaves for gas pipelines should be developed taking into account wayleaves for oil pipelines, power lines and other infrastructure planning. Furthermore, more detailed planning is required around gas versus power transmission and the potential for gas use by the industrial sector.

(v) Decision on LNG Imports

If there is a green light for gas-fired power generation in the short term, then LNG is the only realistic option in which case a project structure must be developed that will facilitate substitution by indigenous resources in the future.

*Critical Decision Hierarchy – Getting to First Gas*




*Source: PwC Consortium*

## 1.2.5. Financing Issues

Kenya's midstream and downstream sector is more advanced but is characterized by infrastructure that is aged and in need of upgrading, both in technical specification and capacity. Furthermore the successful production of oil will require additional infrastructure, in particular the crude oil pipeline and potentially gas infrastructure. Given GoK's infrastructure development commitments, and the need to balance provision of social services and infrastructure development within constrained resources, it is unlikely GoK will be able to fund the entire required infrastructure through public funds. Involvement of the private sector, whether directly or through Public Private Partnerships (PPPs) would likely be an optimal option for required infrastructure development. PPPs /Project Finance structures will also allow GoK to share and transfer the risks involved in developing and operating these projects.

Based upon preliminary high level benchmark estimates as detailed below, the total cost of the infrastructure requirement for the oil and gas sector, excluding the costs of upstream exploration and field development, ranges from between US$ 29b and US$ 32b, if a new refinery and an LNG production plant are developed. The scale of financing required by the sector is substantial in the context of GoK's other infrastructure and budgetary commitments, and in order to maximise the full potential of the sector, GoK needs to actively seek and promote private sector investments for the oil and gas sector. Further, at a cost of US$ 14b for a 10 mtpa 2 train facility, it is likely that an LNG facility would require significant amount of concessional financing to be viable.

*Oil and gas infrastructure cost*

| | Project | Estimated Base Case Capex (US$ m) |
|---|---|---|
| 1. | Crude Pipeline 1 - Common Pipeline Phase 1 | 2,600 |
| 2. | Crude Pipeline 2 - Common Pipeline Phase 2 | 1,800 |
| 3. | Crude Pipeline 3 (East Rift Connector to Lokichar) | 220 |
| 4. | Crude Pipeline 4 (Lake Albert connector to Lokichar) | 1,800 |
| **5.** | **Mombasa-Nairobi Product Pipeline** | |
| *5.a* | *Line 5* | 490 |
| *5.b* | *Line 5 upgrade* | 100 |
| *5.c* | *Line X (c. 2040)* | 368 |
| **6** | **Nairobi - Nakuru Product Pipeline** | |
| *6.a* | *Line 4 upgrade* | 25 |
| *6.b* | *Line 4 upgrade* | 25 |
| **7.** | Sinendet - Kisumu Line 7 | 148 |
| **8.** | Eldoret-Kampala (Uganda) Kigali (Rwanda) | 450 |
| **9.** | Refinery | 1,700 – 5,000* |
| 10. | Storage Conversion/Upgrade | 347 |
| 11. | Storage New Build Programme | 656 |
| 12. | 800MW CCGT plant | 875** |
| 13. | 10 mtpa 2 train LNG facility | 14,000 |
| 14. | 1 mtpa Ammonia plant | 1,200 |
| 15. | 1 mtpa Methanol plant | 1,200 |
| 16. | 5 Bcm/yr Gas pipeline (Lamu to Mombasa offshore) | 780 |
| | | |
| | **Total potential Oil and Gas Infrastructure cost (with LNG production plant and Refinery)** | **28,784 - 32,084** |
| | **Total potential Oil and Gas Infrastructure cost (without LNG production plant and Refinery)** | **14,784 -18,084** |

** Depending on complexity,*

*** Cost for single plant. Multiple plants are likely to be developed*

*Source: PwC Analysis*

(i) State Participation in the oil and gas sector

In light of the analysis above, GoK must decide on where and to what extent it wants to use its own scarce capital resources to take up direct equity positions within the oil and sector. Inward investment cannot happen whilst there is uncertainty in this regard.

Given the scale of investment required for the sector's infrastructure (anywhere between US$ 15b and US$ 32b excluding oil and gas field development costs), along with the constraints on public resources and borrowing capacity that is also required for much needed social services like health care and education, GoK needs to take advantage of existing legislation like the PPP Act, 2013, to attract private sector investment into oil and gas projects.

It is critical to note that not all infrastructure projects are suited to private sector investment, and therefore GoK should encourage private sector investment into sectors where there is an appetite, and focus its own investments in areas that the private sector may find less commercially viable or where initial investment by Government would be necessary in order to make further investments attractive to the private sector.

(ii) Government Support Required

The funding options analysed in this Study i.e. pure public, private sector development and Public Private Partnerships (PPPs) would require various forms of Government support. For instance, the pure public financing option will require GoK to prepare itself to provide sovereign guarantees. PPP structures will generally require a partial risk guarantee or in some cases a sovereign guarantee, and a Government letter of support. GoK will need to start engaging multilateral partners to provide such guarantees for the various development options identified. Without this support from GoK the bankability of such projects may be questionable.

Development Finance Institutions (DFIs) and commercial bank lending for mega projects in developing countries normally requires a sovereign guarantee provided by Government. The Kenyan market has also seen the issuance of Partial Risk Guarantees, in particular to IPPs in the electricity sub-sector specifically for the development of geothermal power generation. This is usually provided by a multilateral institution but requires the local contracting authorities to take out a letter of credit which when called upon will be financed by the partial risk guarantee. This is ultimately supported by the GoK who has a separate agreement with such institutions.

### *1.2.6. Social and Environmental Issues*

(i) Completion of a SESA

The oil and gas sector urgently requires a National Strategic Environmental and Social Assessment (SESA) that covers policy, this study and other sectoral plans and development programs. Further, an Environmental and Social Management Plan (ESMP) is also needed to guide investments in the sector. The former assessment is already envisioned under the Kenya Petroleum Technical Assistance Program (KEPTAP), and NEMA has been identified to conduct the SESA. GoK should ensure that the SESA covers all existing sectoral policies, plans and programs, and that a comprehensive ESMP covering the upstream, midstream and downstream sub-sectors is put into place.

(ii) Strengthen institutional capacity

There is an immediate and long term need for capacity enhancement in environmental management at both National and County levels (waste management for example has now been devolved and is under county jurisdiction). GoK needs to deploy additional financial resources, as well as develop human capital with expertise in oil and gas related environmental management. Without these actions, monitoring, enforcement, compliance, damage and liability assessment, and information dissemination may be compromised.

(iii) Land: Leasing and Resettlement

There is need for standardised guidelines and regulations for the leasing of private and especially community land for oil and gas related activities. GoK should ensure that a transparent and consistent process is adopted across counties to reduce the bottlenecks that investors face, while safeguarding community interests. Further, as significant resettlement is envisioned as a result of upstream field development, as well as infrastructure construction, GoK needs to incorporate adequate public engagement and consultations and adopt best practices for these activities. Given the scale of the crude export pipeline project, and the envisioned time frame, these leasing and resettlement actions are critical and need to be rolled out immediately.

(iv) Local Content: Baseline studies and Stakeholder engagement

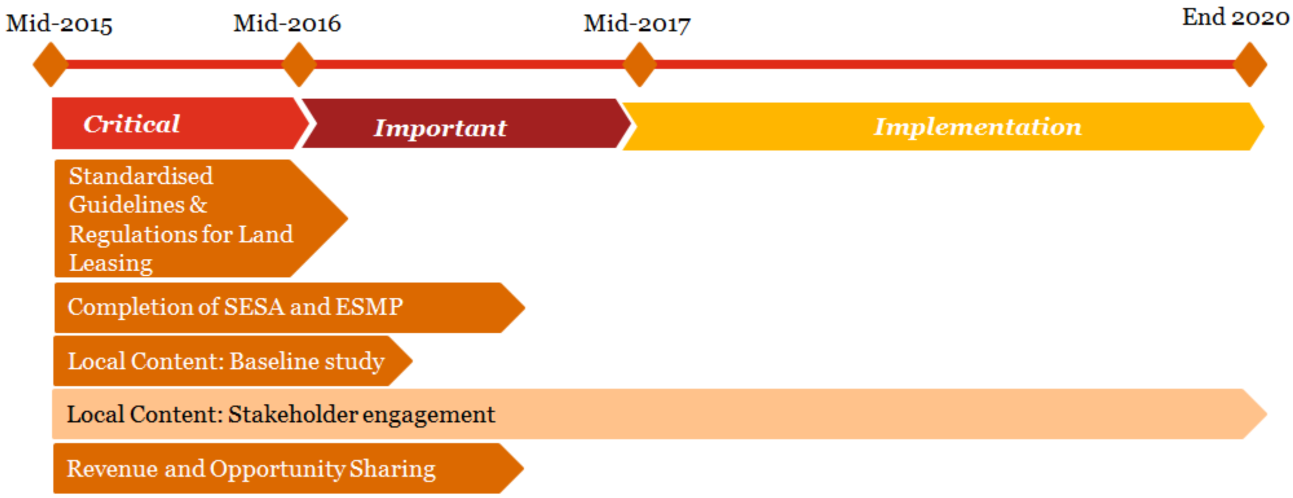
In order to enact local content policy, two prerequisite action need to be taken immediately.
Firstly, GoK, County Governments and upstream investors need to collaborate to undertake a baseline study that identifies the need for skills and supplies in the sector, as well as the current availability of these skills and supplies locally. This will help government as well as investors to arrive at both local content targets and a clearly defined capacity building program that supports achievement of the set targets. This initiative can be expanded to include the wider extractives sector, and form an input towards a harmonised national local content strategy. Secondly, the draft Local Content regulations, while a step in the right direction, are too prescriptive relate to the current stage of the sector's

development, and the targets set may be unachievable. It will be important to subject this draft legislation to full stakeholder participation, including constructive engagement with upstream investors, prior to its enactment.

(v) Revenue allocation and opportunity sharing

In order to enact effective legislation, workable formulae for revenue allocation and opportunity sharing need to be decided on immediately. At present, there is a danger of implementing formulae that are prescriptive down to the sub-county level and which may benefit host communities in the short term but hinder mobility, career progression, development of national capacity, and cost efficiency in the long run. While the emphasis should be on safeguarding local community interests (for example by re-investing a portion of oil and gas revenue in host communities), and promoting their engagement in the sector via employment, and business opportunities, the focus should remain to develop a 'national' oil and gas sector, given that oil and gas is a national resource.

*Critical Decision Hierarchy – Environmental and Social Aspects*




*Source: PwC Consortium*

## *1.2.7. Summary of Additional Studies Required*

The list below provides an aggregate of the recommended studies that need to be undertaken by GoK towards the development of the Kenyan oil and gas sector.

**Critical – Before Mid 2016**

1. GoK must press licensed operators to provide updated information on the results of the seismic and drilling programmes (in accordance with their licence obligations) and should consolidate the projected plans for the sector to encourage its development.

2. A detailed geological study on oil and gas resource potential in Kenya once licensed operators have provided updated information on the results of the seismic and drilling programmes.

3. A comprehensive feasibility study on the costs and economics of upgrade options and on the conversion of KPRL into an oil storage hub.

4. Detailed analysis of specific requirements for converting Mombasa into an import hub, including a review of the fiscal framework.

5. A study on compulsory stock levels, regulation measures, and the mechanism for financing storage facility construction and product holding costs is required.

6. A detailed Power Sector Master Plan in addition to an updated the Least Cost Power Development Plan.

7. A baseline Study on Local Content identifying the need for skills and supplies in the sector, as well as the current availability of these skills and supplies locally.

**Important – Before Mid 2017**

1. A detailed storage capex plan for all products (including LPG) with detailed locations, capacities and timeframes is required.

2. If LNG imports are considered, then this should be planned in more detail including options for project structures that will facilitate substitution by indigenous resources in the future.

3. Gas project economic modelling specific to projects being considered by developers for negotiation of gas pricing terms.

4. An analysis and design of the tariff structures that could be employed for the Crude and Gas Pipelines.

# 1.3. Upstream Oil & Gas Sector

## 1.3.1. Key issues, drivers and constraints

The upstream oil and gas sector in Kenya is in its infancy and there is a great deal of further work and investment to be made before anyone can be confident of the level, location and quality of hydrocarbons in the key identified plays, onshore and offshore. The objective of this Study within this context is not to provide an audit of potential reserves, but rather to collate the available data and information on the activities and findings to date and try to extract from this a reasoned range of potential oil and gas supply scenarios that may eventually be developed.

In almost all cases, the level and extent of drilling and analysis work that has been undertaken by the various licenced operators in Kenya are insufficient at this time to refer to the estimated recoverable hydrocarbons as reserves but only as resources that may or may not be economically recoverable. Nevertheless, the data available is sufficient to be able to provide broad estimates of these resources and likely locations, which we have been able to use in order to derive possible supply scenarios. These, in turn, were used in the evaluation of potential infrastructure needs for the processing, transportation and utilization of oil and gas produced.

The recent downturn in crude oil prices globally raises questions over the appetite and ability of upstream players to fund further exploration activities in Kenya, and eventually over the level of economically recoverable reserves and the timing of their extraction. However, we do not have the information available at this time to attempt to reflect this heightened risk to our derived supply scenarios but instead assume that a reasonable level of upstream investment will be maintained as long as GoK continues to create a framework that is conducive to further investment even when global spending may be reduced.

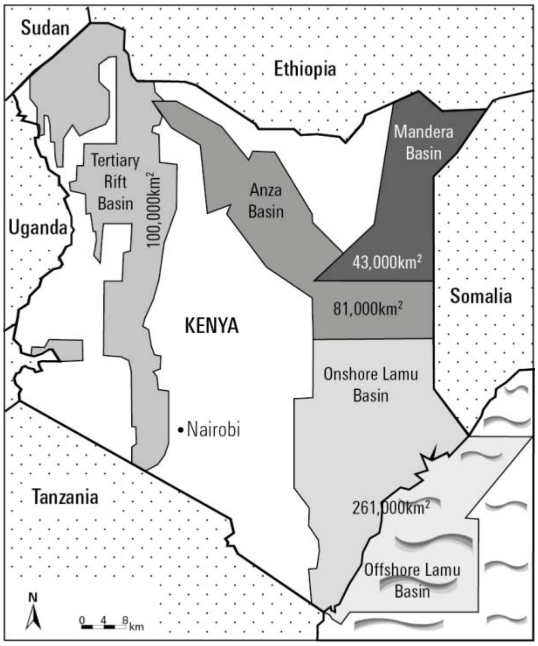
## 1.3.2. Estimating Resource and Supply Potential

Little information was available from the MoEP and the National Oil Corporation of Kenya (NOCK), other than the information available on NOCK's website, which includes historical reports that we consider outdated and so these have not been taken into account. Whilst the production sharing contracts used in Kenya do entitle MoEP to receive detailed technical reports from the operators, no such information was provided to the PwC Consortium.

Despite recent levels of exploration activity and a number of discoveries, Kenya is still very much a frontier exploration play with many companies still evaluating the results of airborne and seismic surveys in order to define and plan their exploration drilling programmes. It will be some years before the level of exploration in Kenya reaches a point where the potential resource can be regarded as firm.

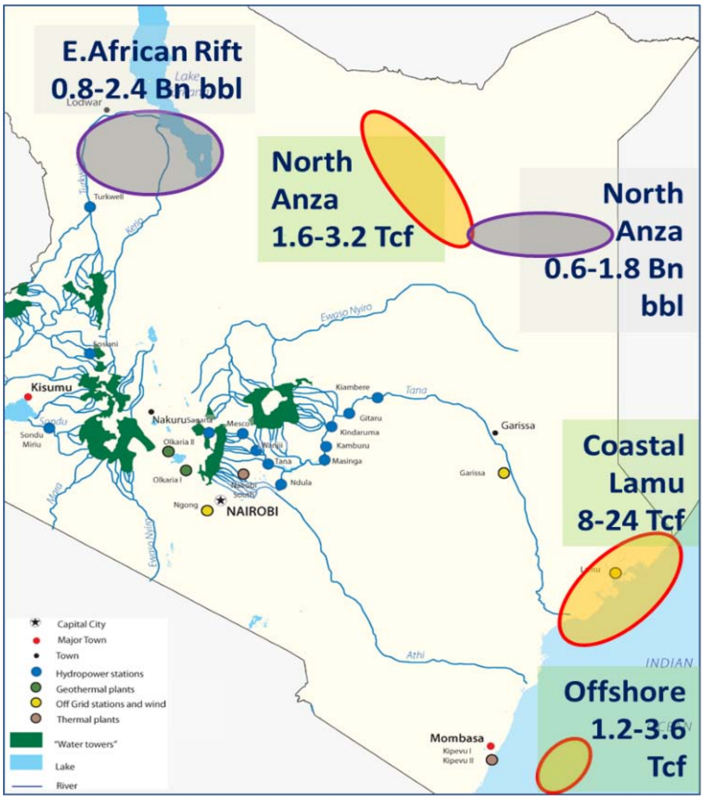
NOCK has identified four large sized sedimentary basins that straddle the country. These are Lamu, Anza, Mandera, and Tertiary Rift (or East African Rift) basins. The sedimentary basins are further divided into exploration blocks.

*Kenya basins structural framework*




*Source: Ministry of Energy and Petroleum*

*Oil and Gas Resource Estimates*




*Source: PwC Consortium Analysis*

Over the last five years, considerable exploration activity has taken place with some 11 wells being drilled in total by the end of 2013 – the majority of which were in the East African Rift. Exploration activity was set to increase further in 2014 with around 20 wells planned. Although it is too early in the play to be definitive, the discoveries to date have been gas in offshore areas and the Anza Graben with oil discovered in the East African Rift. So far seven discoveries have been made in the East African rift and Tullow Oil have reported an estimated resource potential of over 600 million barrels of oil. Oil has also been identified in Mandera with Lion Petroleum estimating a resource potential of some 1.5 billion barrels. Unrisked gas discoveries have been reported in Coastal/Offshore Lamu and onshore in the Anza Graben.

Based on the data collated and discussed with the different players, we have developed the following Base Case to High Case ranges for potential oil and gas resource in place as shown in the figure above. Gas resource estimates are shown in Trillion cubic feet (Tcf) and oil resource estimates are shown in Billion barrels (Bn bbl). Utilising industry norms for recovery factors of 40% for oil and 80% for gas, we have derived the following estimates for the resource in place across the four basins:

*Base case resource estimate*

| Basin | Type of Hydrocarbons | Estimated Resource in Place | Assumed Recovery Factor | Recoverable Resources (bbl/boe*) | First Production |
|---|---|---|---|---|---|
| **East African Rift** | Oil | 2 billion bbl | 40% | 800,000,000 | 2018 |
| **Anza Graben (oil)** | Oil | 1.5 billion bbl | 40% | 600,000,000 | 2019 |
| **Anza Graben (gas)** | Gas | 333 million boe (2.0 Tcf) | 80% | 266,400,000 | 2020 |
| **Coastal Lamu** | Gas | 1.5 billion boe (10 Tcf) | 80% | 1,200,000,000 | 2020 |
| **Offshore** | Gas | 250 million boe (1.5 Tcf) | 80% | 200,000,000 | 2020 |

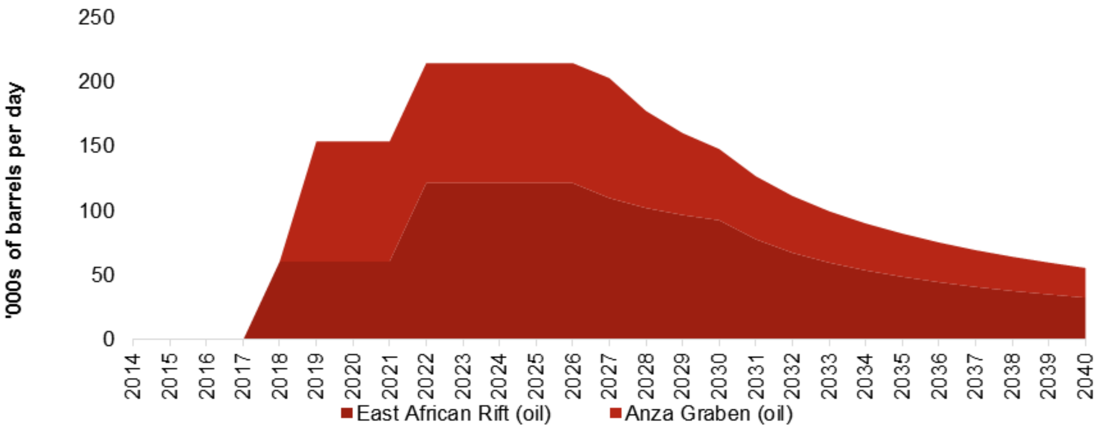
*Boe – Barrel of Oil Equivalent

*Source: PwC Consortium*

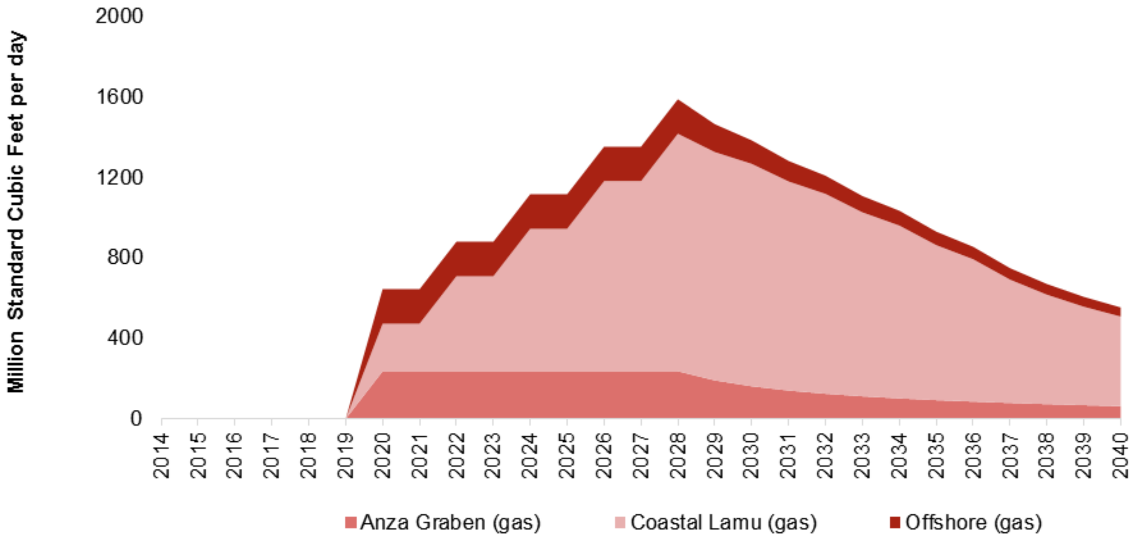
These recoverable resources are then used in the development of oil and gas supply profiles using generic industry rules of thumb and a standard exponential decline curve to produce a template field for each basin.

The assumed fields in each basin are then aggregated and the resultant Base Case Oil and Gas Supply Profiles are provided below:

*Base case oil supply profiles*




*Base case gas supply profiles*




*Source: PwC Consortium Analysis*

### *1.3.3. Estimated Costs of Production*

As part of developing an overall picture and understanding of the oil and gas sector potential in Kenya, we have estimated the level of production costs that might be involved in the development of identified hydrocarbon fields. Our estimated costs are based on industry averages applicable in the region under the following categories:

- Wells
- CPU (central processing unit)
- Other processing
- Infield pipelines
- Jacket
- Operating costs (10% capital costs)

In particular, in using a single well cost assumption of $30 million per well, we must recognize that in reality some wells might be much lower cost than this (especially onshore) whilst others more expensive, and that this would have an impact on individual field economics and investment decisions. Nevertheless, making these assumptions, applying them to the template field production forecasts and discounting over the period to 2040 allows us to provide the following estimated breakeven prices ranges for oil and gas produced from the four basins:

*Breakeven "plant gate" price ranges*

| | US$/bbl, US$/MMBtu |
|---|---|
| **East African Rift** | 20 - 25 US$/bbl |
| **Anza Graben Oil** | 20 - 25 US$/bbl |
| **Anza Graben Gas** | 4 - 5 US$/MMBtu |
| **Lamu Coastal** | 4 - 5 US$/MMBtu |
| **Offshore** | 6 - 7 US$/MMBtu |

*Source: PwC Consortium*

### 1.3.4. Conclusions

In respect of Kenya's upstream oil and gas sector:

- Kenya is still very much a frontier exploration play and it will be some years before the level of exploration reaches a point where the potential resource can be regarded as firm.

- In producing Base Case resource estimates, the PwC Consortium has relied upon high level discussions with operators as well as on publicly available estimates of unrisked resource potential.

- Kenya has good potential for oil and gas production although at this stage well below production levels observed in other more developed oil and gas producing nations. Nevertheless, as further exploration and drilling takes place additional resources may be discovered.

- MoEP and NOCK should reconsider the estimates provided in this Study once more information on oil and gas resource is available as per the requirements in the PSC.

- We understand that there are still uncertainties relating to upstream investment and discussions are on-going between GoK and operators as to fiscal and other terms that might apply. The outcome of these discussions will greatly influence how much oil and gas is produced in Kenya and its timing.

## 1.4. Crude Oil Marketing

### 1.4.1. Key issues, drivers and constraints

Investment in the upstream sector in Kenya will only take place if those undertaking the investments have confidence in the ability to take their product to market. For crude oil this equates to an accessible oil pipeline system that can take their production to the coast for sale in the international market. In the future, once reserves and more certainty over quality and potential supply volumes has been established, then the option of developing a new oil refinery within Kenya to utilize some of the oil produced can also be evaluated. In addition to supply volumes, the demand profile of Kenya and the region will need to be sufficient in order to meet the economies required to run a refinery.

In terms of the development of a crude oil export pipeline, Kenya is in a fortunate position in that there are neighbouring countries whose status of development of their respective upstream sectors are slightly ahead of Kenya's and who seek a transit route to the international market. This enables Kenya to be able to develop a crude pipeline system economically in the short term based on the throughput volumes from other countries and thereby provide a route to market for its own production in a much shorter timeframe than would otherwise be possible.

In order to realise the development of this crude oil pipeline, it is critical to establish the volume profiles that can be committed and the routing of the line taking into account the sources of crude, the location of a potential port, and the physical, environmental and social constraints.

### 1.4.2. Assumed Transit Supply

Both Uganda and South Sudan are land locked and will require pipelines transiting another country (most likely Kenya) in order to export oil internationally. This Report provides a high level view of the transit potential through Kenya and does not attempt to determine production profile scenarios for these countries. Transit potential from Uganda is based on publicly reported estimates of expected annual production and for South Sudan on historic production levels.

South Sudan holds the majority of the former Sudan's total proven reserves of 5 billion barrels of oil (50% recoverable) but at present its only export route is through the existing pipelines in the north where ongoing political unrest between the two nations has resulted in the reduction in production. South Sudan's current production is around 160,000 bbl/day, little more than half its peak rate but it is thought likely that this could recover up to around 300,000 bbl/day should the political situation ease and a suitable transportation option confirmed. Proven reserves in Uganda are at a similar level to South Sudan at 3.5 billion barrels, but the country is yet to commence production. It is estimated that production will be at a level of 230,000 bbl/day commencing possibly as early as 2017/18, although the Government of Uganda is keen to use some of this production in a new refinery (30,000 bbl/day initially building up to 60,000 bbl/day by 2024).

In terms of committing to the use of a new crude oil pipeline through Kenya, South Sudan is likely to seek a level of diversification away from Sudan even though some of the upstream players have interests in both countries and Kenya is by far the best alternative. However, uncertainties over the situation and the need to construct a new connecting pipeline across South Sudan means that volumes from here are unlikely to be available to be committed to the Kenyan pipeline option for some time. We have therefore assumed only half of production (150,000 bbl/day) may be exported through Kenya in a second phase of the project. Uganda is in a different position in that they need to secure the transit route as soon as possible in order for their upstream development to take place. After allowing for their own refinery requirements, we have assumed that Uganda will be exporting 170-200,000 bbl/day through Kenya.

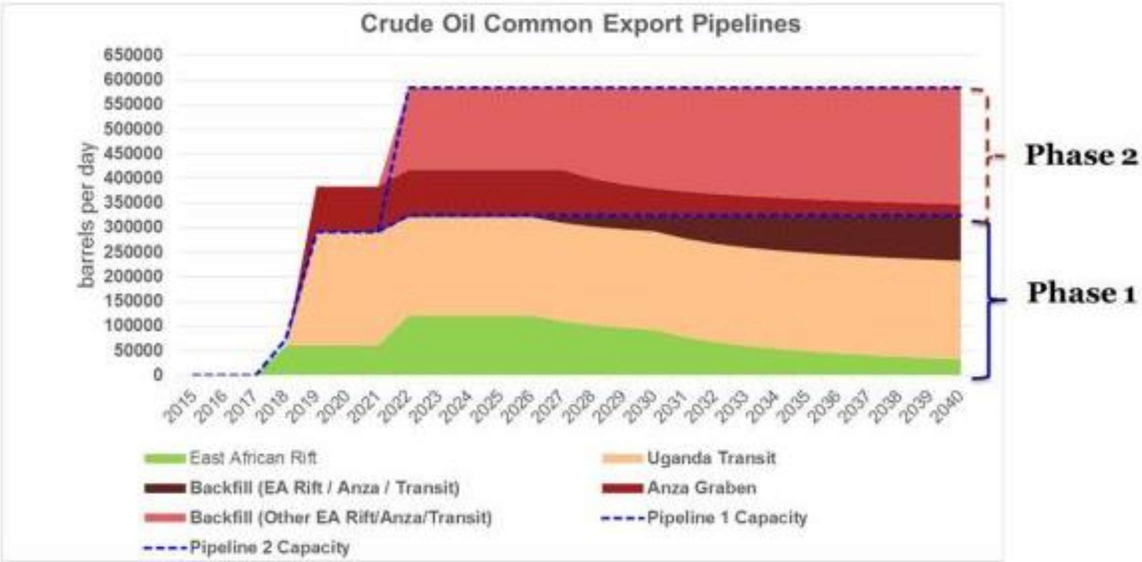
### 1.4.3. Technical and Commercial Issues

There are a number of important technical and commercial issues affecting the proposed development of the crude oil pipeline and its routing. The key issues are listed below:

- Geography: The distances are extensive – especially for a heated pipeline (see 'Quality' below) – in order to not only evacuate Kenyan production but also for the extensions required to link with producing fields in Uganda and, eventually, South Sudan. In addition, depending on the route chosen there will be differences in elevation of around 2,000 metres.

- Quality: There are advantages in the similarity of quality thought likely in oil to be produced from Uganda and Kenya in that it makes commingling both simpler and less commercially sensitive. However, both crudes are thought to be high in wax which means that the pipeline will need to be lagged along its length to ensure continued flow.
- Phasing: Major pipelines like the one envisaged are capital intensive investments requiring relatively high levels of volume throughput from soon after commissioning in order to provide an adequate level of return. However, unlike gas pipelines, oil pipelines cannot be easily increased in capacity later by applying additional compressors and so the decisions as to what capacity should be provided and when are critical. Below we include an illustration of a likely 2-phase development whereby the first pipeline would largely serve Ugandan producers and Kenyan production from the East African Rift, with a second phase bringing in further Kenyan production and other transit volumes, possibly including South Sudan.

*Illustrative initial use and backfilling of crude oil pipeline capacity*




*Source: PwC Consortium*

- Crude oil prices: The economics of the pipeline itself will not be affected directly by the recent downturn in oil prices as tariffs will be independent of this. However, there is the potential for lower than expected throughput volumes if upstream investments are delayed. In our opinion, there has already been a level of price recovery in international crude prices that is likely to provide comfort to upstream investors in the region such that we do not think the short term field developments will be greatly delayed, if at all.

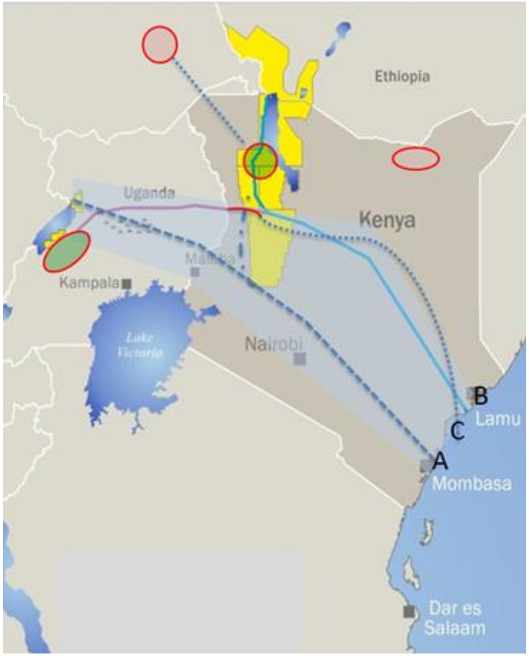
## 1.4.4. Pipeline Routing Options

There are three primary options identified for the routing of the proposed crude oil pipeline through Kenya:

A. Southerly Route: Running from Eldoret and following the oil product pipeline towards Nairobi and on to Mombasa, where a new export terminal would have to be constructed. This route favours Ugandan reserves as it is the shortest route to market for this, but since the discovery of hydrocarbons in Kenya's East Africa Rift and Anza basins this would be suboptimal from a sourcing perspective. In addition, the obtaining of rights of way and complications with construction work in the congested areas around Nairobi and Mombasa add to the difficulties associated with this route.

B. Northerly Route: Runs from Lokichar to Lamu along the LAPSSET corridor. A slightly longer pipeline route for Ugandan oil but much closer to potential Kenyan production. This route fits with Vision 2030 and is likely to offer fewer construction issues as the areas concerned are largely undeveloped. The main issue with this route is the requirement for major development of the port at Lamu to support the use of large tankers and the impact this may have on existing business in the area.

*Crude Oil Export Pipeline – Routing Options*




*Source: PwC Consortium Analysis*

C. Modified Northerly Route: The developers of the Turkana oil fields have worked on modifications to the Northerly Route to try and address some of the issues it raises. The primary alteration would be to redirect the pipeline to the south of Lamu where an oil export terminal would be developed and then fed into tankers via an offshore mooring thereby providing the deep water needed by the tankers.

## 1.4.5. Project Structuring

The successful development of the proposed crude oil pipeline will require the effective addressing of a number of key areas, including:

- Intergovernmental approach: It is clear that the development of the pipeline will require the agreement and cooperation of at least two Governments; Kenya and Uganda. Operators will not be able to progress with the final design and construction until there is a clear bilateral agreement in place setting out the governance framework and the terms and scope for appointing a lead contractor.

- Key components: The pipeline system design will be dependent on the routing selected, but is likely to consist of some or all of the following:
    - Connecting lines from fields;
    - Central crude stabilization unit and storage facility;
    - Heated common export pipeline of 270,000 to 330,000 bbl/day initial capacity;
    - Export and storage terminal; and,
    - Sea line and single point mooring system (Option C).

- Company structuring: It is envisaged that the common sections of the system (i.e. from Lokichar to the point of export) would be financed and operated by some form of joint venture company vehicle. Connecting lines into this system would be owned by others and have separate tariffs, and different companies would be responsible for sections in other countries where pipelines transverse national boundaries.

- Ownership: It is envisaged that those producers seeking to utilise the pipeline would become the primary shareholders, with their respective long term capacity commitments underwriting finance raising from debt markets.
- Expansion: The structure put in place would need to facilitate the development of the second phase pipeline, which may have a different ownership although we suggest a single management team for operational purposes.

### 1.4.6. Conclusions

In respect of the crude oil export pipeline:

- The pipeline project can only progress once an Intergovernmental Agreement has been put in place between Kenya and Uganda.
- As part of this, a decision needs to be made on the preferred route through Kenya, and then the process to obtain the rights of way must be commenced at the earliest opportunity.
- The policy and regulatory structure governing the pipeline , specifically a crude pipeline tariff needs to be set to enable potential investors to conduct analysis of their expected returns.
- Following the adoption of the Intergovernmental Agreement as well as a clear tariff structure, the key proposed Phase 1 users must agree on the appointment of a lead contractor with overall responsibility for the design of the project. This will require the procurement of transaction advisory services to provide financial, legal and commercial advisory services in the development process.

## 1.5. Downstream Oil Sector

### 1.5.1. Introduction: Key issues, drivers and constraints

Despite extensive investigation and various studies conducted over the last decade by former and current Government equity partners, no viable refinery upgrading or renewal project for the Mombasa refinery owned by KPRL has so far been identified that would attract either equity partnership or third-party funding. Faced with the prospect of increasingly uneconomic operations, crude processing at the 53 year old hydroskimming facility was halted in September 2013 and the refinery was effectively 'mothballed'.

Since then, Kenya has relied solely on imports of oil products. In 2013 oil product demand was 4,592 million litres, 43% of which was diesel, 24% of which was petrol, and 15% for Jet fuel, with the rest of demand being mainly split between kerosene and fuel oil and to a much lesser extent LPG (60 million litres). Nairobi and its environs dominate overall demand accounting for 65% to 70%, with the three key towns of Nakuru, Eldoret and Kisumu accounting for 20 % with the remaining 10% to 15 % demand being consumed in country and coastal areas including Mombasa.

Kenya has developed a product pipeline network which extends to over 1,200 km, following the Northern Corridor from the import point in Mombasa, through the major conurbation of Nairobi to the towns of Nakuru and Eldoret with a spur line to Kisumu. From these major cities volumes are loaded onto tankers for transport within the cities and towns, to other locations in Kenya and to neighbouring countries. The major pipeline from Mombasa to Nairobi is over 35 years old and due to its internal condition its working flow rate, at approximately 610 $m^3$/hour, is well below its installed capacity rate of 880$m^3$/hour. The flow rate is also below the current pipeline demand for Nairobi, which has resulted in increased road bridging, particularly from Mombasa to Nairobi.

The overall shortage of throughput capacity is not sustainable, and needs a comprehensive upgrading, with only one working jetty for product imports, a single under–sized pipeline and limited storage, and little planned downtime available for maintenance of either the pipeline or jetty, which are now aged.

The pipeline system and major storage terminals are owned and operated by KPC, a parastatal owned 100% by GoK. KPC is addressing the principal short-term pipeline issues including the replacement of the existing Mombasa-Nairobi pipeline with a new 20 inch line which will initially supply 880 $m^3$/hour, and is scheduled for operation in 2016. Further expansion of this line to 1,830$m^3$/hr is currently being envisaged for 2023, but may be required much sooner to meet the expected growth in demand. Other projects under consideration to upgrade oil transit capability include a possible pipeline extension from Eldoret to Kampala and pipeline upgrade from Sinendet to Kisumu, and a terminal jetty that will expedite exports by ship.

With the Mombasa refinery being mothballed, the current importing configuration has very limited operable oil product storage. Typical average supply cover is estimated at between 5 to15 days cover, and such is the squeeze on available tankage, that large cargo imports are often delayed during discharging. Furthermore, a recent audit by an external consultant indicated that as much as 60% of KPC's existing tankage is in need of major refurbishment

Given the forecast pattern of cargo importation, the required tank capacity for operating stocks needs to provide at least 20 days cover, and with demand set to more the quadruple in the period to 2040, this requires a properly planned programme of capacity renewal and growth to achieve and then sustain sufficient operational storage capacity. Currently, some 132,000 $m^3$ in road fuel storage and 70,000 $m^3$ of airport storage is being installed by KPC in Nairobi.

In addition to increases to operating stock capacity, Kenya needs a properly planned and administered approach to compulsory stocks. These stocks provide the strategic reserves within the country to cope with periods of crisis, and provide the essential supply chain robustness to stabilise behaviours and prices. The IEA recommends 90 days of strategic stock cover, a policy adopted by much of Europe and the US. Africa generally is very weak in this area, and Kenya will need to not only consider setting compulsory stocks targets, but also how best to administer both costs and physical stocks, and to enforce compliance.

Currently there is heavy congestion at tanker loading points at major cities, with suppliers increasingly loading at Mombasa, in an effort to avoid long waiting times. This adds to congestion in the cities and along the highways which already struggle with high levels of road traffic.

## 1.5.2. Outlook for Kenyan oil demand

### 1.5.2.1. Demand scenarios

In the Base Case, Kenya petroleum product demand is forecast to double by 2030 and double again by 2040 (average growth rate of 6.4% between 2014-2040), based on average GDP growth rates of 6.6% per annum between 2014-2040. In the High Case, demand is assumed to grow threefold from 2030 to 2040, based on the development of abundant oil and gas reserves and the realisation of Vision 2030. In the Low Case the economy is assumed to continue as is with no real impetus from limited new crude oil discoveries and limited investment and petroleum product growth is forecast to be 4.7% per annum between 2014 and 2040. A large majority of the growth in demand is expected to be for petrol and diesel, mainly as fuel in road transportation as the economy grows and as Kenya transitions from a low income country into a newly industrializing, middle income country. Under all these scenarios there is a strong need to replace existing and develop new oil product distribution and storage infrastructure to ensure there is an efficient supply of petroleum product to the consumers across Kenya.

### 1.5.2.2. Regional pipeline fed demand

Kenya is the major transit route for imports by Uganda, Eastern Democratic Republic of Congo and more recently Southern Sudan, accounting for 65%, 14% and 17% of transit volumes respectively with North eastern Tanzania, Burundi and Rwanda making up the rest. Transit volumes are currently lifted from Nakuru (25%), Eldoret (45%) and Kisumu (30%) and currently accounts for 30% of total pipeline demand. Underlying product requirement in the 'transit' countries is forecast to grow threefold by 2040 based on regional forecasts and information provided by KPC.

However, a key sensitivity on transit volumes will be the impact of the planned (initial 30,000 b/d) 60,000b/d Ugandan refinery at Hoima. If the refinery proceeds as planned, transit volumes are unlikely to exceed current levels until 2030.

Coordinated forward planning with an understanding of the composition of both the local and transit geographical demand will be fundamental to the development of the required regional infrastructural over the forecast period.

Notwithstanding these uncertainties, successfully implemented, transit volumes should remain an attractive opportunity to earn income from neighbouring countries albeit at slower net growth rates than within Kenya itself.

## 1.5.3. Oil product supply

### 1.5.3.1. Kenya refining

Kenya's existing refinery was commissioned in 1960 and is now mothballed with the last crude oil being processed in September 2013. This is a hydroskimming refinery which, depending on the crude oil processed, produced some 35% to 40% fuel oil and therefore less of the lighter/middle distillate more valuable products (like gasoil/diesel and petrol) which are now in much more demand. As a result the refinery has been loss making in comparison to other newer refineries being developed in other countries based on the cracking processes with much higher yields of gasoil/diesel and petrol.

Although the construction of a new refinery employing modern cracking technology may seem attractive with the recent discoveries of crude oil in Kenya, in reality for a refinery to be sustainably profitable it needs to be world scale (approaching 400 kb/d), sufficiently complex to compete with the best regional refining complexes (i.e. full conversion to distillate fuels and integrated with chemical installations) and located in a region without sufficient existing refinery capacity. Currently, none of these conditions apply to Kenya, nor are they expected to for the foreseeable future. The extent and timing of indigenous production is not yet clear, and it is very unlikely that this specific waxy crude will always achieve the highest free market price, year-after-year in Kenya. Similarly, a new refinery, designed to produce a specific yield pattern will almost inevitably be called upon to make process feedstock changes over time in order to optimise its financial performance. For all these reasons, commercial developers look to keep the crude oil supply chain and refinery crude oil and feedstock selection fully independent.

Indeed, the decision on whether or not there should be a refinery needs to be made not upon the proximate availability of crude oil, but upon the fundamental crude supply options, the scale and breadth of local area demand, and the competitive outlook for refining in the region over the medium and longer term. The costs and benefits over such a period do inevitably involve uncertainty, and when comparing to the importation of oil products, strategic assessment is probably appropriate.

As is discussed below, given the huge regional petro-chemical complexes, Kenya has neither the scale nor the breadth of secondary industries to economically justify such a facility. Strategically, Kenya should be looking to develop East African trade that its geographic position naturally supports. To exploit this situation, and to provide cost effective energy solutions for Kenya and boost oil trade with its neighbours, this reality needs to be faced, and an open and transparent market based pricing system consolidated along the oil supply chain, from crude oil exports through to end customers purchase of oil products.

Kenya is currently a regulated market although there has been significant progress in developing towards a market related pricing system. The monthly Open Tender System (OTS) for product is competitive and an import parity equivalent. The closest logical bulk product pricing source is the Arabian Gulf. Bulk product import prices would generally be referenced against Arabian Gulf prices plus freight to Mombasa. Any refining option would need to be able to produce a basket of products with values equal to the equivalent product import parity levels to compete. In the same sense, any crude oil produced locally and sold to a refinery would need to be priced at market prices. Subsidising crude oil sales to the refinery or oil product prices to the local market would only lead to losses at some point along the chain, leading to deficits in Government budgets - this is not sustainable as many countries, even oil rich countries, have experienced.

Globally over the last few years, the scale of new refining has outstripped forecast demand. This has led to lower or even negative margins for smaller refineries or for refineries with older technology. Many older refineries have started to shut down (including in other countries in Africa) as they are not competitive relative to the newer larger refineries with lower processing costs given significant economies of scale. This trend is expected to continue in the longer run towards 2030. With many new mega refineries being developed in the Middle East (2.2 million b/d) with capacity of 300,000 to 400,000 b/d (more than three to four times current demand in Kenya and transit countries), it is unlikely that a new refinery in Kenya will be able to compete against these, unless local demand reaches at least 200,000 b/d, which may then provide sufficient economies to justify developing a new refinery in Kenya. In other words, it will be cheaper for Kenya to import products from nearby Arabian Gulf rather than process crude oil through a new refinery with capacity of less than 200,000 b/d. We therefore believe that investors are unlikely to want to invest in a greenfield small/medium sized refinery in Kenya – probably for at least the next decade.

Having said this, questions can be raised for why Uganda is currently developing a much smaller 30,000 60,000 b/d refinery. Our understanding is that the Ugandan refinery is a strategic requirement of a country that has recently discovered crude oil and that is landlocked (unlike Kenya). It is very likely that imported product into Kenya transported to the Kenya/Uganda border will be cheaper than product produced from the refinery in Uganda. Hence, volumes produced in Uganda will only be sold locally and further inland (DRC or South Sudan) where prices are higher given additional transport cost, and will not be able to competitively supply the Kenyan market, assuming efficient operations within Kenya.

Whilst the market remains long in refining capacity, Kenya's best economic interests would be to avoid refinery capital expenditure, and focus on becoming an efficient importer of oil products, with a robust supply chain capable of supporting Kenya's growing fuel requirements with secure, lowest cost, modern specification fuels, and using this platform to further its interests as a pipeline transit supplier to neighbouring countries where there is a sound economic basis. As markets rebalance, and as new refining technologies get developed, assuming Kenyan demand continues to grow rapidly, a review of the refining option should be done at a later date – likely to be beyond 2025.

### *1.5.3.2. Mombasa importation hub*

Given the discussions on refining above, it is very unlikely that it will be economical to reopen the Mombasa refinery even if it is upgraded. Upgrading to a point of being able to produce more middle distillate and less heavy products may not be possible or would be very costly and hence not economical. There is however a good option to convert the existing infrastructure at the refinery into an import terminal and oil product storage facility at relatively low cost. This will include clearing the site process units and reconfiguring crude oil tankage and pipeline configurations for oil products. The key to transforming the effectiveness of Mombasa as an oil import and storage facility is to network together the physical oil receiving facilities at the port, the storage and handling facilities of KPRL, OMC's and KPC, and co-ordinate the overall management of hydrocarbon flows from importation planning, customs clearing and administration, storage (including compulsory storage) and pipeline scheduling of inland and transit batches. A new terminal will ease congestion at the existing depot in Mombasa. Furthermore, coaster deliveries by sea to towns and cities along the Kenyan coast should be considered (as is being done for supplies to Zanzibar and to naval ships) and can further ease loading congestion at Mombasa.

## *1.5.4. Oil product storage*

### *1.5.4.1. Oil stock policy*

A suitable strategic stockholding ensures that a country can continue to function in times of supply disruption howsoever caused, avoiding hoarding, panic buying or predatory pricing practices. The numbers of days of product stock that GoK decides to hold as strategic stock is essentially a judgment call based on the perceived level of risk of a product stock out and the implications for the Kenyan economy compared to the cost of investment in tank capacity and the holding cost of the product stock. It is clear that the current 5 to 7 days stockholding is very low and leaves Kenya very susceptible to major supply issues if for any reason imports or pipeline supply is interrupted for longer than 5 to 7 days, and that the IEA standard of 90 days whilst a desirable in principle, is unlikely to be achieved in the short term. The study offers interim alternatives based upon emergency cover being supplied to different regions. Given the financing required to build storage capacity to hold higher levels of stock and considering Kenya's geographical location, we would suggest that finished products be built up progressively. An independent Government controlled compulsory stockholding of 40 days is proposed as an interim target. This would provide Kenya with greatly improved Supply Chain robustness, considerably better than other African states, enhancing Kenya's attractiveness for growth and investment initiatives. The best practice recommendation for developing storage is through administration via a single Agency or CSE (Compulsory Stock Entity), usually an independent, not for profit organisation, and operating under a Government mandate.

It is further recommended that an industry and Government consultative committee is set up, charged with the responsibility to make detailed implementation proposals, to cover not only target setting and administration, but also to examine the additional policy areas below:

- Designation of responsibility for stockholding ; compulsory stocks can be held either at Government owned storage facilities, held in dedicated CSE's or held by the Oil Industry. Benchmarks in developing nations including Germany and Switzerland appear to favour a CSE.

- Designation of responsibility for policy enforcement; this can be covered by a CSE to allow for easier audit of quality and quantity of storage set aside for compulsory stock.

- Designation of responsibility for financing the obligation;
  Though a CSE Kenya will be able to track the cost of renting storage and interest charges of the cost of product and proposing the level of supplementary charge on the final consumer price to ERC for approval

  – GoK will also need to consider the bearer of the risk of market price fluctuations and determine whether an additional element should be added to the inland sales price mechanism to finance these costs.
  – Furthermore if a decision is made requiring market players to hold strategic stock, there will be an additional financial obligation to them. Given these considerations, and as recommended above, GoK needs to pursue a careful consultative approach in setting these policies.

### *1.5.4.2. Storage facilities*

Principal existing storage facilities, which are connected via the KPC pipeline system, are well located in the main areas of demand. However, these terminals will need significant upgrading to cope with additional capacity requirements rising from (i) a forecast 4 to 5 fold increase in demand by 2040, and (ii) the recommended strategic storage policy that envisages 40 days stock to be held local to the main demand centres. As product demand grows over the period the volume of strategic stock increases as does the required tankage capacity. If Kenya were to develop 40 days' worth of storage plus 20 days tankage capacity to cover ullage at Mombasa (i.e. to ensure sufficient tankage capacity to allow ships to offload without waiting for capacity availability and incurring demurrage costs), by 2040 around 4.8 million $m^3$ of additional capacity would be required in addition to the 0.9 million $m^3$ currently in operation or under development. Given the age of the existing facilities and concerns expressed in recent terminal technical audits that estimated as much as 60% of existing tankage is in need of major refurbishment, it is proposed that an accelerated programme of refurbishment takes place within 3 years to restore all tanks destined for long term use.

### 1.5.5. LPG

There are currently 3 licensed LPG storage and bottling facilities with the following capacities: Mombasa – 15,490 metric tonnes (MT); Nairobi – 1,404 MT; and Eldoret – 100 MT. This is insufficient to meet current demand, estimated by KPC to be around 91,600 MT. The overall objective of developing the LPG facilities in the country is to ensure availability and accessibility of LPG at cost effective prices, promote the use of LPG as a household fuel among both the urban and the rural population and enhance socio-economic development. KPC has sponsored a detailed study by external consultants for the economic viability and construction of LPG facilities across the country. According to their estimates, if the supply constraints are removed, consumption could be in excess of 300,000 MT. The study recommends two phases of capital expenditure to increase LPG storage; one between 2013 and 2014 totalling US$ 83m and one in 2024 totalling US$ 26m. The facilities envisioned are recommended to be situated in Nairobi, Nakuru, Eldoret, Kisumu and Sagana, and to be undertaken by KPC with an aim to incorporate private sector investment in the projects.

These investments will result in an additional 5,200 MT of capacity in phase 1 and 8210 MT in phase 2 which will reduce the storage inadequacy currently being experienced and make LPG more accessible.

### 1.5.6. Conclusions

The existing infrastructure for importing and throughputting oil products within Kenya is in need of major refurbishment and is unable to cope with any further increase in demand. In addition, old and inadequate storage capacity is a major threat to security of supply and Kenya will not be able to cope with supply shortages for more than one week, after which the economy would be severely impacted. Furthermore, oil product demand in Kenya is expected to grow rapidly into the future, more than quadrupling by 2040.

Recent crude discoveries, whilst welcome, cannot be allowed to become a distraction for resolution of the need to accept the need to convert the old Mombasa refinery to be part of a well-integrated import hub, providing capability to rapidly discharge world-scale import cargoes, to batch and feed a high capacity product pipeline, and provide a contribution to Kenya's compulsory stock tankage requirements.

Within Kenya, old infrastructure is currently being slowly replaced and plans exist to add or expand existing pipeline and storage capacity in the future. In a number of cases, this will need to happen a lot sooner than planned to meet rapidly growing demand. Beyond that, the precise timing of additional development and expansion will need to be monitored against updated demand forecasts.

Kenya will require three large terminals, two of which would be located around Nairobi. These should provide not only additional operating and compulsory storage, but modern, safer, faster loading gantries to enhance truck loading capacity, but be located in areas better suited to access the new roads and grow areas of the city.

Investments into LPG storage facilities should also be prioritized, in order to eliminate bottlenecks in the supply chain and ensure availability of product at affordable rates.

Kenya will also need to undertake a consultative process to firm up compulsory stock policy requirements and proceed to implement these policies to ensure that the country has a cushioning for any unforeseen interruption of supply.

The opportunity also needs to be taken to modernize administrative systems, and working together with the oil industry and retailers, aim for 24 hour, 7 days per week operation that will allow night deliveries, and reduce congestion caused by road tanker traffic.

Finally, although it is recognized that the current circumstances within the region are unlikely to be favourable to refining for at least a decade, due to the volatile nature of the oil market and potential for new technologies, that a review be carried around 2025 to examine whether regional supply/demand balances or other events that cannot currently be foreseen, have changed in any significant way that could justify consideration of a new refinery. Even if this were to be the case, it is believed the most appropriate location would be coastal.

# 1.6. Gas Sector

## 1.6.1. Introduction: Key issues, drivers and constraints

There is no existing gas industry in Kenya and the challenge is to create an environment whereby the necessary levels of investment are more likely to take place such that the natural gas industry can be established and developed. This is a more difficult objective for natural gas than for the oil industry due to the relatively high levels of infrastructure investment required upfront in order to connect the point of supply (e.g. gas field) with the market.

The starting point, therefore, is to establish whether there is sufficient potential demand for gas to justify the early investment required in the upstream sector to explore and produce the gas. From this demand projection we are able to evaluate the likely levels of cost associated with bringing gas to market, and hence estimate not only the size of market for indigenous resources but also the netbacks that might be available to producers. Hopefully, this can provide the basis for further upstream investment in the country and so instigate the development of the natural gas sector.

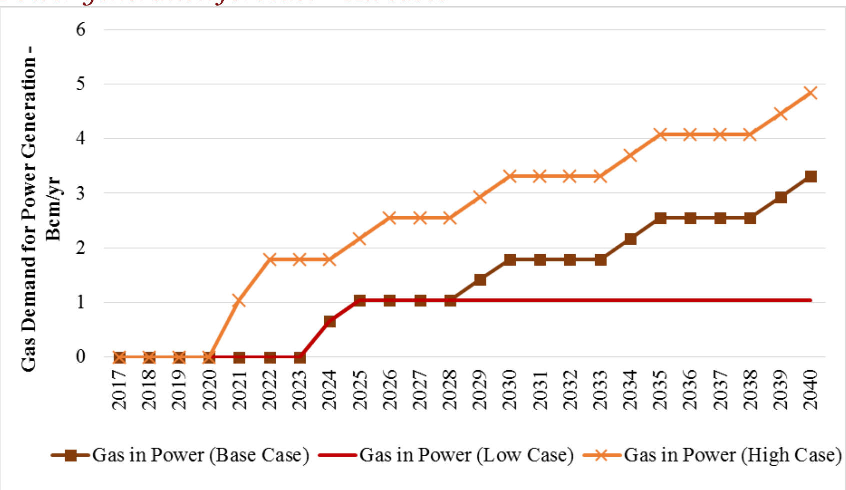
## 1.6.2. Outlook for Kenyan gas demand

### 1.6.2.1. Gas demand in power generation

Kenya holds ambitious plans for the development of new power generation facilities to meet growth expectations but although actual growth rates in electricity demand, at an average of 6.5% over the last 5 years represent a significant year-on-year increase, this is from a low base and the Vision 2030 projection represented a CAGR of more than twice this rate at 14%. At the time of writing, there is an oversupply of generation capacity compared to existing demand and MoEP's plans to bring an additional 5,000MW of capacity online by 2017 is now only expected to happen by 2020, subject to sufficient demand creation. We have assumed that this delayed version of the 5,000+MW plan does take place and that the Vision 2030 target of 15,000MW total installed capacity is realised by 2040 rather than 2030.

We have developed a Base Case and a High Case for gas use in power generation within this overall power capacity projection. In the Base Case we assume that 1,085MW of gas-fired capacity is developed around 2025 using indigenous resources. Further 800MW stations are then brought on at 5 yearly intervals. 800MW plants would require around 0.8 bcm of gas per year (60% load factor). In the High Case 1,885MW is developed around 2021-2, using imported LNG initially. Again, incremental gas-fired capacity is added in 800MW steps every 5 years, commencing in 2025. We also considered a Low Case which follows the Base Case in the early years but with no further volumes being added post-2025.

*Power generation forecast – All cases*




*Source: PwC Consortium Analysis*

These three Cases are depicted in the diagram above. It should be noted that a key factor affecting the potential use of gas in power generation is the GoK decision in terms of the use of coal as a major feedstock. Our Base

Case and High Case both assume that the coal plants currently planned for development (2,300MW by 2020) will not be constructed. This is based on the lower projected growth in electricity demand but also because gas offers a number of advantages over coal as the thermal generation option of choice.

In addition to gas's environmental, efficiency and speed of development credentials over coal, our analysis shows how indigenous gas demonstrates considerable price advantages over either imported or indigenous coal on a whole project cost basis. At current oil prices, imported LNG is also at much lower price than coal although this advantage diminishes as the oil price rises.

Given this situation, GoK should delay the planned coal power projects until an updated and robust energy demand forecast has been developed, and an energy generation mix based on the viable options has been decided on. Should the planned coal power projects proceed before these steps are completed, indigenous gas production may fail to develop as a result of a lack of a domestic market, while Kenyan consumers are held hostage to a more expensive power source. Further, as part of arriving at an energy generation mix, a detailed study on Kenya's indigenous coal, and its viability as a feedstock for power generation should be conducted.

#### *1.6.2.2. Gas demand in other sectors*

Whilst in our opinion it is gas use in power generation that may form the central core of the development of the gas sector in Kenya, there are other areas of potential gas demand:

- Ammonia and methanol production: If there are sufficient volumes of gas resources that can be developed on a competitive cost, then ammonia and methanol plants of world scale size could each provide a demand of around 80 MMscf/d (0.8 bcma). However, the global methanol market is likely to be oversupplied in the medium term and may not represent an attractive market for producers. An ammonia plant to meet domestic demand in Kenya maybe a good option, especially if it could be located inland and close to the primary areas of fertilizer demand.
- Gas to liquid (GTL): Very few of these plants have been developed and those under consideration generally are of a scale that demands very high gas volumes (e.g. 4 tcf gas field or an annual volume of 4.5 bcm to meet the feedstock needs of a 50,000 bbl GTL plant). At this stage of development, Kenya probably has insufficient resources to make this option viable.
- Industrial, commercial and households: The geographic and [population spread] in Kenya is not conducive to a high level of penetration of the small consumer market by natural gas. The best opportunity for use in the industrial sector would be for new industrial parks that may be developed adjacent to new gas pipelines constructed to new 'anchor loads' such as power generation of ammonia plants. The aggregate demand from such parks is likely to be under 0.5 bcm.
- Transport: CNG and LNG in transport has only been attempted in countries with an established natural gas network, as the costs of developing a national infrastructure to support gas use as a transportation fuel can be prohibitive. In the absence of this, LNG for use in heavy goods vehicles could remain an option in the event that an LNG import/export facility is developed in Kenya.

### ***1.6.3. Key Monetisation Options***

#### *1.6.3.1. LNG export*

The LNG sector has developed a long way over last 40 years or so, especially regarding the scale of modern projects and the different ways that projects can be structured and financed. Today, we are facing the prospect of oversupply with several major new international projects due to come onstream over the next few years. This increases the importance of scale in order to ensure cost competitiveness and at this time Kenya has not firmed up enough gas resources to make LNG export a realistic option for developers, although it will remain an option going forward as reserves are firmed up.

### 1.6.3.2. Gas-fired power

Kenya's recent increase in power generation capacity has largely been concentrated in renewables. The standard Feed-in-Tariff for these sources ranges from around $0.08 to 0.12/kWh. We believe that gas may offer GoK a better option for thermal generation (necessary to provide network operational base load stability when there is a high level of renewable generation on the system) than either oil or coal, and if it can be shown that gas-fired generation can produce electricity at levels or below this range then the case for its use will become compelling.

### 1.6.3.3. Gas products

Many countries in the East African region are looking to develop ammonia and/or methanol export plants to utilise their own substantial gas resources. However, the international market looks like being oversupplied in the medium term, at least, and this is unlikely to be an attractive option for Kenyan producers. The development of an ammonia plant inland where the products would be targeted at local demand and displacing imports could, on the other hand, be an economic project and could potentially play the role of 'anchor load' thereby facilitating the construction of new gas pipelines and opening up the market to smaller consumers.

### 1.6.3.4. Gas use in industry

The scale of Kenya's likely demand as an industrial feedstock, process heating or on-site heat and power generation may be insufficient to make the development of an extended gas pipeline network economically feasible. However, if anchor loads are identified in locations that facilitate such infrastructure development then this could provide an attractive upside to gas producers and a potential boost to economic growth in the industrial sector.

## 1.6.4. Strategic Issues

### 1.6.4.1. Kenyan electricity demand and role of gas-fired power

Given the results of our economic analysis and the uncertainties surrounding the levels of gas in place across the main exploration basins, it is quite clear that the power sector will play a critical role in the proposed development of the gas industry in Kenya. At present there remains uncertainty over the likely rate of economic growth in electricity demand and this will have a dampening effect on new capacity development. Just as important will be the energy mix within the overall envelope of required generation capacity. Our analysis indicates that gas in the form of mid-merit CCGT plants should be capable of producing electricity at levels equating to or better than renewables, and offering significant savings over alternative thermal generation which would have environmental issues attached. Urgent work is required to establish a more robust projection of electricity demand and to investigate whether energy policy needs to better reflect the qualities of gas. Pending this work, planned coal power projects should be suspended, given that generation using indigenous gas would have cost advantages over both imported and indigenous coal and that proceeding with the coal projects will discourage development of indigenous gas production.

### 1.6.4.2. Gas pipeline development

If there is a green light for the development of gas anchor loads, then gas pipeline infrastructure development is likely to fall on the critical path as far as making this a reality. Whilst the capital costs are not insubstantial, the levels of volume throughput associated with anchor load flows should mean that resultant tariffs are low enough not to be a driver. However, the projects both upstream and downstream of the pipeline will be at risk if the pipeline development is delayed and for this reason we would advocate an approach that seeks to put in place a basic outline of key pipeline/infrastructure corridors linking the main demand areas with the likely points of gas production, and to commence the process of planning permission and wayleaves.

### 1.6.4.3. Kick-starting the gas sector

In attempting to instigate a new gas industry, there is always a risk that projects do not happen because of a mismatch in timing or uncertainties over project developments at other points in the value chain. For this reason, we believe that further consideration should be given to the potential import of LNG to meet power generation demand in the short-to-medium term, with the plan that this would be displaced by (more competitively priced) indigenous gas supplies as these were developed. Given the ability to import LNG through floating storage regasification units (FSRUs) with minimal additional fixed infrastructure costs being incurred and the growth in use of short term leases for such vessels, then such a solution could be both fully consistent with GoK energy policy and financially sound.

### *1.6.5. Conclusions*

The main conclusions arising out of the work carried out on the natural gas sector in Kenya are as follows:

(i) Role of gas in power generation

GoK should confirm its commitment to gas as a major contributor to the nation's generating mix. This can be justified on purely economic grounds, but combined with its environmental credentials (compared to any other form of thermal power generation) and operational advantages (compared to renewables) then the case becomes compelling. Doing so would provide the necessary level of confidence for the upstream players to commit to the level of activity required to firm up the finds to date and bring them to production.

(ii) Decision on LNG Imports

If GoK does affirm the role of gas in power generation under (i) above, then this needs to takes into account the timing of the first gas plants to meet the power plan needs. Urgent questions remain as to whether new baseload-type plant will be required in the next few years and a coherent view is required in order to ensure that new gas projects are viable and in the best interests of Kenyan consumers. The cancelled LNG-to-power project(s) failed to consider the broader implications in terms of the desired energy mix and the potential impact on other (e.g. upstream) investments. A comprehensive study is required across the power and fuels sector on the projected demand for electricity in Kenya and how this is best met, taking into account the strategy for developing indigenous resources (i.e. coal, gas), the operational needs of the growing system, output prices and investment constraints as well as environmental considerations.

If this results in a green light for gas-fired electricity in the short term, then LNG is the only realistic option in which case a project structure must be developed that will facilitate substitution by indigenous resources in the future.

## 1.7. Environmental and Social Discussion

Kenya has fairly adequate Environmental and ESIA policies and legal frameworks. However much of the emphasis is on project approval processes, rather than on a life cycle approach to minimizing environmental and social impacts. Environmental monitoring and project follow-up are considered part of the ESIA. Nevertheless, in most cases actual enforcement is inadequate, environmental monitoring is insufficient and monitoring data is not widely disclosed to the public and affected stakeholders. Moreover, most Counties have insufficient control and enforcement mechanisms during the post-ESIA approval phase due to limited human, technical and financial capacity.

Environmental legislation in Kenya is provided in over 77 statutes. The Environmental Management and Coordination Act (EMCA) was enacted in 1999 as the main and comprehensive framework law to guide the environmental management systems. The Energy Act (2006) created the Energy Regulatory Commission which was mandated to formulate, enforce and review environmental and health and safety standards for the energy sector in cooperation with other agencies. The Occupational Safety and Health Act (2007) (OSHA), protects the safety, health and welfare of persons at work, as well as third parties at risk as a result of activities by persons at work.

There are still however several gaps in Kenya's existing environmental and social framework as it relates to the oil and gas sector. Of particular concern is the increased execution of terrorism related incidents and other forms of violent crimes mainly in Nairobi, Rift Valley, Northern, North Eastern, Lamu and Mombasa in the Coast, the petroleum industry stakeholders have become more alert to the need for effective mechanisms that assure Kenya's and the East Africa region's energy security. The security issue is also of importance since a number of incidents have been recorded in Kenya's prospective oil and gas sedimentary basins. Security remains a major priority for the residents of areas with potential for upstream projects.

With strongly increased petroleum exploration activity and the potential for petroleum production over the next three to four years, the volume of activity in the Government of Kenya's petroleum sector is expected to multiply. Increasingly activities will take place in environmentally sensitive and technologically complex areas, which will dramatically increase the level of expertise required in the GoK. The importance for the GoK to be able to extract optimal revenues from this opportunity, to adequately forecast and manage revenues, as well as manage the potential macro-economic, social, and environmental consequences and the impact on economic development justify a significant capacity building effort in the GoK along all aspects of the extractive industries value chain.

Additionally, upcoming upstream oil and gas production areas are currently not included in the list of projects required to undergo Environmental Impact Assessments. There are also no specific legal guidelines or technical procedures and standards on the disposal of upstream oilfield and offshore waste and gas flaring. Guidelines on gas flaring as well as waste classification, tracking, storage and transfer, and treatment, among others, need to be developed. Waste management has been delegated to County Governments post-devolution and there is a need to establish capacity building procedures for the new institutions in terms of oil field waste disposal and related issues.

This Study recommends a number of decisions as discussed in the critical decision hierarchy above that GoK needs to take in order to bridge the gap in the environmental and social legislation that is particularly impacted by the oil and gas sector.

## *1.7.1. Multiplier Effects of Oil and Gas Sector Development*

Nations that have developed oil and gas resources have typically experienced strong economic growth from revenues generated from exploration and production activities. Other than direct revenues there are other indirect benefits that a nation can achieve. By adopting a targeted approach in developing its oil and gas resources, the following spill -over effects and more can be expected in Kenya.

1. *Increased local supplier activity and stimulation of other sectors*

   Procurement of capital goods, consumables and services can act as a multiplier for local economic development which will contribute to employment, skills strengthening as well as development of local suppliers. The local supplier base and enterprises will also benefit from technology transfer through cooperation with foreign suppliers which will bridge the gap of local technical capacity limitations.

2. *Job creation and increased technical skills*

   Oil and gas development in Kenya can have a flow on effect of knowledge transfer to businesses and the labour force. At the moment, sourcing the right people and managing human capital in the oil and gas sector is a concern that will need to be addressed in order to increase local content in to the sector. The need for local manpower participation will lead to the emergence of relevant training opportunities within institutions of higher learning. Kenya has several well established public and private universities and technical institutions that are placed to provide the relevant training. As discussed above, through partnerships with international institutions and oil and gas market players, these institutions will have the capability to develop the curricula and put together a faculty to provide the required training.

3. *Opening up Northern Kenya*

   Oil and gas will further open up the currently marginalized areas of Northern Kenya where oil and gas activities are ongoing. A key impediment to building local capabilities in oil and gas exploration areas is low access to education and loss of pupils as they advance through the school levels. In Turkana county some of the contributing adherences to education access has been the lack of proper infrastructure, poor security as well as the county's demographics which is large in land mass (68,307 Sq.Km) and low in population density (13 persons per Sq.Km) as per the 2009 census.

   As the region opens up to oil and gas exploration and with changing a culture in favour of schooling we expect increased access to education which will position the community to take part in oil and gas activities in the county and countrywide. Kenya's development of oil and gas resources will however need to take a targeted approach to ensure equitable distribution of resources and other benefits to the local community. Issues around land rights, community displacement and distribution of oil resources should be implemented in consultation and partnership with governing bodies in the Central Government, County Government and the local community to ensure that the rights of the communities in question are preserved.

4. *Emerging technologies*

   As a multiplier effect of oil and gas exploration, a number of emerging technologies could emerge along the oil and gas value chain which would further develop a domestic market for oil and gas products. To effectively promote emerging technologies the government may need to create an enabling environment that allows the private sector to innovate, in addition to making the necessary investments in infrastructure. Chapter 7 explores the possibility of using CNG (and LNG) to fuel vehicles, and highlights the need for the government's investment in the transportation and storage infrastructure as well as public transportation fleets. Likewise Chapter 6, considers the need for investment in LPG facilities, and an LPG development plan, to ensure availability and affordable product prices that can promote its use as a household fuel.

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# *Introduction and Background*

# 2. Introduction and Background

The World Bank has appointed PricewaterhouseCoopers (PwC) and its consortium consisting of Channoil Consulting Limited and QED Gas Consulting (PwC Consortium) to undertake this consultancy with the primary objective of this Final Report ('This Study") to support the Government of Kenya (GoK) towards the development of a Petroleum Sector Master Plan for Kenya

Given that Master Planning is a continuous process, this Study is structured to provide a basis for discussion amongst oil and gas sector stakeholders in Kenya regarding the future of exploration, production and infrastructural development in the country.

Below we present the analytical process and approach that has guided the development of this report, followed by an outline of the rest of the document.

## 2.1. The Process and Approach

Under the Consultancy, the PwC Consortium has undertaken an analysis of the strategic options and the resultant decision hierarchy for the GoK to catalyse development of the oil and gas sector and maximise the monetary, social and environmental value of potential oil and gas resources in Kenya. The analysis also included the development of financial / economic models for oil commercialisation options and gas monetisation options. Selected personnel by the MoEP will be trained on the use of these models as part of a capacity building initiative that will better equip the Government to understand the impacts of delays, costings and funding required amongst other metrics for the options identified.

The project has been under the direction of a Steering Committee led by Mr. Martin Heya, Commissioner for Petroleum in the Ministry of Energy and Petroleum. The Steering Committee also draws membership from other key stakeholders including the Kenya Oil and Gas Association (KOGA); The Petroleum Institute of East Africa (PIEA); The National Treasury; The Kenya Revenue Authority (KRA); The Energy Regulatory Commission (ERC), The National Environment Management Authority (NEMA), Kenya Pipeline Company (KPC), National Oil Corporation of Kenya (NOCK), Kenya Petroleum Refineries Limited (KPRL) and The World Bank.

The findings presented in this Study have been sourced from data gathering from the above mentioned institutions as well as other stakeholder discussions; including civil society organisations, individual upstream and downstream investors as well as other Government agencies (a complete list has been included in Appendix B).

***Timelines***

This Study commenced in March 2014, and an Inception Report was submitted to the MoEP on 05 May 2014, followed by an Interim Report on 17 July 2014. Thereafter, the first stakeholders' workshop was held on 31 July 2014 to discuss the submission of the Interim Report, and a second workshop on 21 November 2014 to discuss preliminary findings for oil commercialisation and gas monetisation options. A two week feedback period was allotted to allow stakeholders the opportunity to comment on the findings presented during the second workshop. There has nonetheless been ongoing stakeholder discussion through individual meetings / interviews and data gathering throughout the engagement. This Draft Report encompasses comments received from the above forums undertaken during the analysis period.

***Approach and Methodology***

The project has been developed in 4 phases:

**Phase 1**: The inception report which provided a summary of the current status of Kenya and its oil and gas sector.

**Phase 2**: The Interim report focused on:

A review and validation of existing policies, plans, and studies which incorporated:

- benchmarking of selected countries (Canada, Ghana, India, Israel, Malaysia, Nigeria, Trinidad and Tobago, and Turkey) for upstream, midstream and downstream oil and gas highlighting the lessons learnt.
- an analysis of the current legal, regulatory, environmental and social policy framework, and identification of the gaps that future policy would need to address.

A review of supply potential which included an assessment of potential supply of oil and gas in the Anza Graben, East African Rift, Coastal Lamu and offshore basins, using publicly available information and informed by insights following discussions with oil and gas exploration companies in Kenya.

Forecast of demand to 2040 - the Consortium developed several demand outlook scenarios for:

- Oil - Three demand scenarios were developed (Base Case, Low Case and High Case) which considered the large flagship Government projects such as Vision 2030 and LAPSSET.
- Gas - The Demand outlook scenarios for gas to 2040 were largely based on the demand for gas-fired power generation as identified in the Least Cost Power Development Plan ("LCPDP") for 2011 to 2031, and the 40 month 5,000+MW plan developed by GoK.

**Phase 3:** This report encapsulates the key elements of the interim and inception reports, and as described below develops the strategic options into a set of actions and decisions that must be made within varying timeframes, with emphasis being made on immediate action within the next six months from submission of this Study.

# Overview and Major Issues

# 3. Overview and Major Issues

## 3.1. Background

This section presents a brief overview of Kenya and its economy. A basis for our discussion around the commercialization of the oil and gas sector, covering both the upstream and downstream stages is formed by the insights we provide on the developments in the energy sector. Thereafter, Kenya's infrastructure needs are then analyzed with a view to highlight the funding gap. Subsequent sections in the Chapter address the relevant legal and regulatory framework following a benchmark process against similar countries. We identify the policy issues and discuss how this Study looks to address these issues through each of the Chapters within this document.

### 3.1.1. Kenya's location

*Figure 3.1: Map of Kenya*


Kenya is a coastal country located on the east coast of Africa bordering the Indian Ocean. Situated between Ethiopia and Tanzania, the country sits along the equator on 580,367 sq. km of land. Only about 2% of Kenya's total surface area (11,227 sq. km) is comprised of water with a coastline along the Indian Ocean spanning over 3,477km. The country's population stands at 45.01 m[2] and its population is estimated to grow at a rate of 2.11% per year.

[2] CIA World Fact book, December 2014

## 3.2. Kenya country performance

### 3.2.1.1. Macroeconomic Context

Kenya achieved lower middle income status in 2012 according to national statistics released on September 30, 2014. The base year was updated from 2001 to 2009 and consequently GDP was 25% larger as of September 2014 than earlier estimated[3]. Now the eight largest African economy, Kenya has an estimated Gross Domestic Product (GDP) of US$ 62.7b as at 2014[4] and remains the largest in East Africa. This has particularly been driven by a comparatively skilled workforce; a port that serves the region as well as a liberalized trade environment. Private sector participation in key industries such as energy and telecommunications, in parallel to the liberalization of trade has driven growth of its middle class and attracted Foreign Direct Investment.

In 2013 Kenya National Bureau of Statistics published a revised economic growth rate of 5.7% and the World Bank forecasted a growth rate of 4.7% in 2014 and 6% in 2015. The World Bank attributes this growth to aggregate demand, fueled by strong consumption and investment. This growth is also identified as broad-based owing to the fact that all sectors make a contribution to the GDP.

### 3.2.1.2. Overall Country Performance

The country's macroeconomic performance is a critical measure for inward investment as returns on investment will be influenced by the strength of the economy.

Kenya has displayed a strong economic performance demonstrated by the growth in the country's GDP from US$ 40b in 2010 to US$ 55b in 2013. According to the IMF World Economic Outlook Database, GDP is expected to peak at US$ 104b in 2019 representing an 89% increase over a period of 6 years. However the past couple of years have seen a number of terrorist attacks and security threats that have weakened the performance of some key sectors of the country, tourism being the worst hit. The level of foreign investment on the other hand has not changed much over the period.

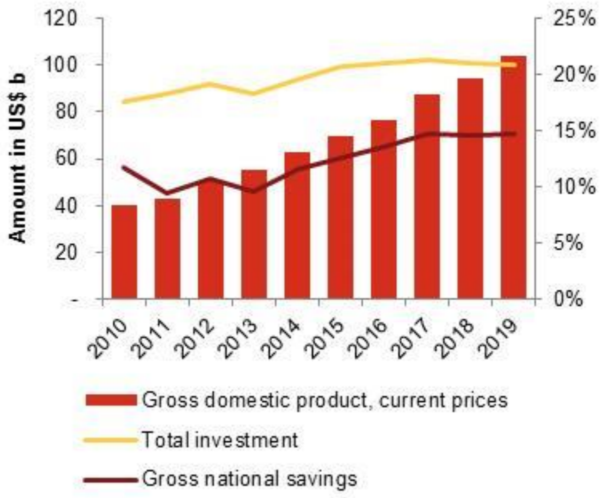
GoK has continued to maintain its monetary policy inflation target of 5%. Inflation in 2013 was recorded at 5.72% while expectations for future inflation rates remain below 6% from 2016 onwards (IMF World Economic Outlook Database, October 2014).

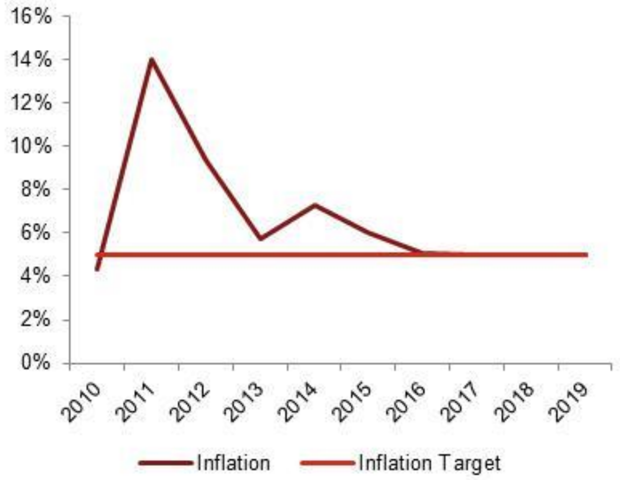
Foreign investment into Kenya is protected under the Foreign Investment Protection Act (FIPA), whereby investors are allowed to repatriate profits and remit dividends to their home countries. There are however taxes associated with foreign earnings that need to be complied with. The graphs below illustrate the increase in total investment in line with the growth in GDP. The IMF also projects higher national savings between 2014 and 2019 as a portion of the country's GDP.

[3] World bank (http://www.worldbank.org/en/country/kenya/overview#1)
[4] World Economic Outlook Database, International Monetary Fund

*Figure 3.2: Kenya's gross domestic product vis-à-vis gross national savings and total investment*

*Figure 3.3: Kenya's inflation rate vis-à-vis its inflation target rate*




*Source: IMF World Economic Outlook Database*

The establishment of 47 counties and the operationalization of their Governments following the implementation of the 2010 Constitution has been fast tracked over the last 2 years. There have however been transitional challenges the Government has been faced with, in particular cash management in setting up county operations as well as budget allocations. It is important that GoK successfully streamlines the functionalities of county Governments to ensure county operations contribute positively to the ultimate development objectives of the country.

## 3.2.1.3. Agricultural sector

For many years the mainstay of the Kenyan economy has been the agricultural sector which contributed 26% of total GDP in 2013. According to Kenya Agricultural Research Institute (KARI), the sector has contributed to 27% of GDP indirectly through linkages with manufacturing, distribution and other service-related sectors. Not only is it the greatest contributor to the Government's revenue (45%) but it also contributes to over 75% of industrial raw materials and more than 50% of the export earnings[5].

## 3.2.1.4. Financial sector

The contribution by the financial sector to Kenya's total GDP increased from 6.5% in 2012 to 7.2% in 2013. In the near future, the financial sector seeks to develop a robust financial system that is expected to encourage further FDI and safeguard the economy from external shocks. Pursuant to Vision 2030, the Government is focused on deepening the country's capital market by developing a ten-year Capital Markets Master plan and reforming the bond market to further support future FDI. In January 2014, the draft master plan was published and distributed for public comment[6].

Some of the ways in which the CMA mater plan intends to transform the financial sector include:

a. Building on market reforms to address regulatory and institutional constraints to strengthen market infrastructure, oversight and governance standards.
b. Stimulating innovation to broaden the financial products and service offerings such as derivatives, assessment management while supporting the emergence of an Islamic banking hub in Kenya.
c. Streamlining and augmenting funding for developmental projects under Vision 2030, and providing alternative financing sources for the implementation of country wide initiatives such as devolution.

[5] Policy responses to Food crisis in Kenya by KARI (http://www.foodsecurityportal.org/kenya/food-security-report-prepared-kenya-agricultural-research-institute)
[6] Capital Markets Authority (http://www.cma.or.ke/index.php?option=com_content&view=article&id=436:cma-to-engage-stakeholders-on-the-capital-markets-master-plan&catid=14&Itemid=232)

According to the most recent Kenya Economic Update released in June 2014 by the World Bank, the economy is said to remain resilient with positive sentiments following a successful Eurobond issue in the same period that raised US$2b. During this debut issue, the country was seeking to borrow US$2b but investors offered over US$8b; pointing towards an increased vote of confidence by investors on the country's economic fundamentals.

Kenya's banking sector has grown significantly in recent years, and is the most sophisticated in Eastern Afirca. The country has seen a regional and international expansion of its banking network with numerous subsidiaries and branches of indigenous commercial banks being opened within East Africa.

The table below presents the share of the banking sector to GDP from 2012 and 2013:

*Table 3.1: GDP / sub-sector assets*

| GDP / sub-sector assets | 2012 | 2013 |
|---|---|---|
| | US$ millions | US$ millions |
| Nominal GDP | 39,563 | 44,004 |
| Banking Assets | 27,088 | 31,322 |
| Pension Assets | 6,378 | 8,072 |
| Insurance Assets | 3,615 | 4,243 |
| Saccos Assets | 1,090 | 3,886 |
| **Total** | **38,171** | **47,524** |

*Source: Central Bank of Kenya (US$ conversion based on year end US$/KES exchange rates)*

As at 31 December 2013, the banking sub-sector comprised of: 43 commercial banks; 1 mortgage finance company; 7 representative offices of foreign banks; 9 microfinance banks; 2 credit reference bureaus; 2 money remittance providers and 112 foreign exchange bureaus – all being regulated and supervised by the Central Bank of Kenya.

*Table 3.2: Banking sector performance*

| | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|
| **Profitability in US$ millions** | | | | | | |
| Profit / (loss) before tax and exceptional items | 617 | 633 | 937 | 1,007 | 1,268 | 1,460 |
| Profit / (loss) after exceptional items | 618 | 634 | 972 | 1,007 | 1,268 | 1,451 |
| Profit / (loss) after tax and exceptional items | 430 | 446 | 727 | 720 | 882 | 1,031 |
| | | | | | | |
| **Trend in Banks' Liquidity** | | | | | | |
| Liquidity Ratio (%) | 45% | 40% | 45% | 37% | 42% | 39% |
| Minimum Statutory Ratio | 20% | 20% | 20% | 20% | 20% | 20% |
| Excess / (deficiency) | 25% | 20% | 25% | 17% | 22% | 19% |
| Gross Loans / Deposits Ratio | 73% | 72% | 73% | 78% | 77% | 81% |

*Source: Central Bank of Kenya (US$ conversion based on average annual US$/KES exchange rates)*

Kenya's banking sector performance improved significantly from 2012 to 2013, represented by a 16.6% increase in profit before tax and exceptional items, while total net assets also grew by 16% to KES 2,703.4b (US$ 30.32b) from 2012. Total deposits held by commercial banks increased by 23.3% from KES 1,707.8b (US $19.15b) in 2012 to KES 1,935.7b (US$ 21.16b) in 2013 as a result of increased expansion, introduction of agency banking, remittances and export receipts. According to statutory requirements, commercial banks are required to maintain a minimum liquidity ratio of 20%. The table above illustrates the sector was safely above the threshold and therefore within the compliance framework.

Kenya's foreign currency reserve increased from US$ 6.2b in December 2013 to US$ 7.4b in August 2014 (4.85 months of import cover). Within a period of 3 weeks during August 2014, the Central Bank of Kenya accumulated additional reserves of US$ 1.1b following the issuance of the Eurobond.

### 3.2.1.5. Transport sector

In 2013 Kenya's GDP attributable to transport (and communication) was over 9.1%.

According to PwC's 2013 *Africa Gearing Up* report, which focuses on the future of Africa's transportation and logistics industry, Kenya's population and agricultural activity are heavily concentrated in the southern half of the country along the transport corridor that links Mombasa to Nairobi, further to Kisumu and then onto Uganda. The country's infrastructure backbones – including the principal road artery and its major power transmission and fiber optic infrastructure – have followed this route. As a result, the northern half of the country is sparsely populated and characterized by fragmented infrastructure coverage.

The division between upper and lower hemispheres of the country has affected the ability of the agricultural, manufacturing and other significant sectors from attaining their maximum potential to contribute to Kenya's GDP. The oil and gas sector presents an opportunity to propel economic development and sustainable infrastructure in the relatively low inhabited areas.

### 3.2.1.6. Potential economic contribution of Oil and Gas

With the recent discoveries of potentially viable oil the key drivers of the economy may shift in the near future. According to the Kenya Economic update of 2012, Kenya has recorded a relatively weak economic performance attributed to three main factors: internal (political) shocks, the lack of natural resources and economic fundamentals such as high interest rates resulting from high inflation[7]. With this in mind, if proved to be commercially viable, the recent oil and gas finds could greatly impact the economy in several ways assuming a prudent and stable macroeconomic policy and management framework:

1. **A developed oil and gas sector will aid Kenya in reducing its debt burden and further sustain its strong macroeconomic outlook.**
   Following the successful issue of its first Eurobond the multiplier effects and economic contributions made by the oil and gas sector will ensure Kenya services its repayment plan. This will ensure a stable macroeconomic environment with affordable interest rates, stable exchange rates and low inflation. In 2014, the IMF's overall assessment of Kenya on debt sustainability and other indicators was positive.
2. **Increased financial sector growth and contribution to the overall GDP due to increased foreign investment.**
   Foreign Direct Investment into Kenya almost doubled from US$259m (KES 22.7b) in 2012 to US$514m (KES 45.18b) according to the 2014 World Investment report by the United Nations Conference on Trade and Development (UNCTAD). This trend would only be further facilitated by an economy which would be partly supported by oil and gas revenues, and the development of an entire new sector.
3. **Development of the northern half of the country where some of the oil blocks are located.**
   As earlier discussed, the Northern part of Kenya is characterized by sparse population and fragmented infrastructure development. The oil and gas sector provides an opportunity for towns in this region to be revamped and made conducive for economic development. The LAPSSET corridor project which aims to develop a series of large scale infrastructure projects in the northern part of the country will also be partly co-dependent upon the successful development of the oil and gas industry.
4. **An opportunity for the manufacture of ammonia - a key raw material for fertilizers.**
   Not only will this greatly reduce the cost of farming but gas production for commercial purposes will also provide an economically attractive route for gas monetization and the development of the gas infrastructure.
5. **Multiplier Effects –** The economic multiplier effects from the development of the oil and gas sector are numerous, however it needs to be noted that the exact specification, both in terms of monetary and social benefits are difficult to quantify given the complexity and interdependencies within the economy. In general, it is well accepted in economic literature that infrastructure development, and specifically oil and gas sector development has a high, if not the highest multiplier effect in economic development and the growth curve. These can be generally divided into the following areas:
   - Construction Employment – the capital intensive projects, such as the crude pipeline and the required associated projects, require skilled labour whose compensation during the project construction period is a "one off" injection of consumption investment that albeit is temporary in

[7] Kenya Economic Update, World Bank, June 2013

nature pending the time required for the build phase of projects, is nevertheless a significant addition to the economy in terms of money that is then reinvested into consumable goods and services.

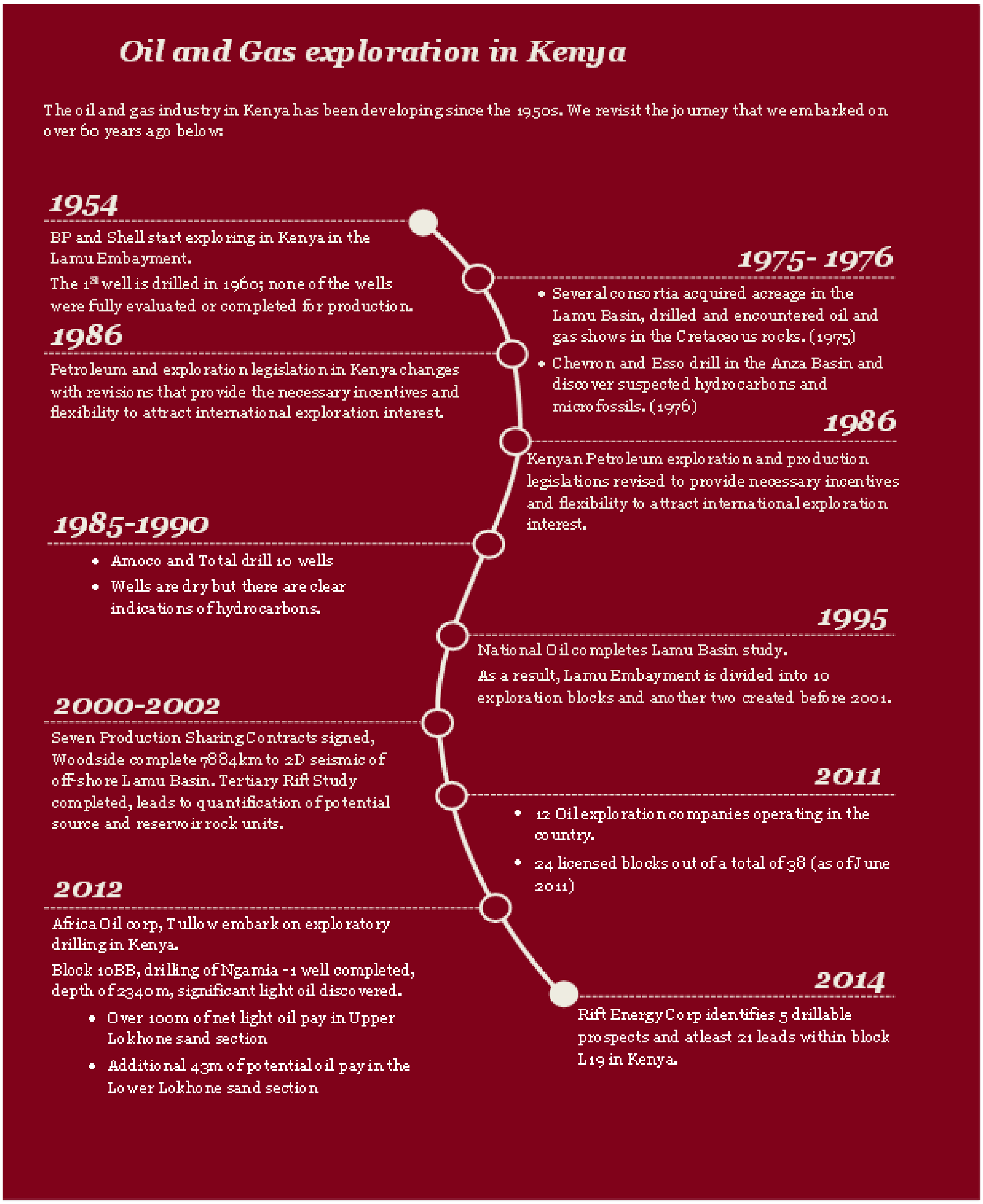
- Sustainable Employment – this is employment that will be generated by the need to operate and maintain the infrastructure projects after completion. Pending the nature of these, and their labor intensitivity, this is likewise a significant potential for multipliers effects via reinvesting into consumable goods and services of the employed personnel.
- Local Suppliers and Content – the use of local suppliers as much as possible, within the construction projects phase as well as within the operations and maintenance phases will be a crucial element in increasing the multiplier effects of the original project costs. Whilst this is a much broader subject, that we address in this study, its effect upon the multiplier is worthy of noting.
- Interdependent projects: whilst transportation, roads and ports for instance, are not directly oil and gas sector investments, they are clearly needed and indeed planned for the projects in the sector. Such related infrastructure is significant, and in many cases is required as a pre-requisite for the main projects to be completed. This also relates to telecommunications, housing, and the associated supply chains of construction materials and technology equipment. The Lapsset project, which the GoK has been planning to implement as a major corridor for economic development in the north, as well as the connection to neighbouring countries, is a good example of this, since the crude oil pipeline and a number of upstream developments would potentially be a part of this wider development programme.

Further discussion on the multiplier effects are presented in the Environmental and Social Chapter.

## 3.3. Overview of Oil and Gas exploration in Kenya

Oil exploration in Kenya began in 1954 and by 2012 only 33 oil wells had been drilled. The exploration process was not only slow but also yielded dry wells. In 2012 Tullow Oil discovered an oil potential of about 300 million barrels in Turkana. These results marked the onset of further exploration activities with a view to reach commercially viable resources. By 2014 Tullow had discovered an accumulated resource potential of well over 600 million barrels[8].

*Figure 3.4: Oil and gas exploration in Kenya: historical context*




*Source: National Oil Corporation of Kenya website (www.nationaloil.co.ke)*

[8] Information Center for the Extractives Sector (ICES), http://ices.or.ke/sectors/oil-gas/, accessed on 24 February 2015

According to the Information Centre for the Extractives Sector (ICES) the Ngamia area had potential for 660 million barrels of oil as of September 2014 with the Amosing, Agete and Twiga areas having potentially 231 million, 163 million and 142 million barrels of oil respectively. As of September 2014 Africa Oil had reported potential of up to 2.9 billion barrels of oil in the East African Rift (Turkana) and Anza Graben (Mandera) basins.

## 3.4. Recent developments in the Oil and Gas sector

### 3.4.1.1. Crude oil prices

Between June 2014 and January 2015, global crude oil prices declined more than 60% as a result of fears of excess supply.[9] Despite a marginal rebound of around 10% between January and February 2015, the overall drop in prices is likely to slow down exploration activity in Kenya over the medium term. In mid-February 2015, Tullow Oil announced a cut in its exploration budget for Kenya alongside a cut in its global exploration budget from US$300m to US$200m, with a view to focusing investment on its producing assets in West Africa.[9] This change of strategy (Tullow had earlier indicated that it did not intend to cut its Kenyan budget) may be as a result of the prolonged slump in prices. In the prevailing crude oil price environment, upstream players will delay exploration activities and development decisions, while they closely monitor global supply and demand; this is leading to a slowdown in the pace of upstream activity in frontier areas like Kenya. For Kenya's wider economy, the decline in crude oil prices and subsequently refined product prices has resulted in lower inflationary pressure.

### 3.4.1.2. The Finance Act, 2014

The Finance Act, 2014 has had a significant impact on the investment climate perception for the oil and gas sector in Kenya. Several upstream investors view the reintroduction of capital gains tax (at between 30% and 37.5% of net gains) as a factor that will affect their ability to attract funding for further exploration activity in the context of declining global crude prices, especially for those players seeking to develop their blocks via farm out transactions.

### 3.4.1.3. Social and security concerns

In October 2013, Tullow Oil suspended operations in 2 of its block i.e. Blocks 10BB and 13T, after local residents in Turkana County held protests to demand job opportunities. In October 2014, operations at some installations in the county were again suspended as a result of protests connected to staff layoffs by one of Tullow's subcontractors. From a security perspective, most of Kenya's exploration activity is occurring in areas prone to security challenges; the Turkana area has recently experienced inter-communal conflict whereas the Mandera and Coastal areas have experienced attacks associated with the Al-Shabaab terror group. Given the financial as well as time related impacts as a result of these shutdowns, GoK will need to ensure enhanced security to support efficient operations in the sector, and GoK, upstream investors and local communities will need to dialogue and collaborate towards resolving revenue allocation and opportunity sharing issues; otherwise security and 'social license' related shutdowns may delay the development of the upstream oil and gas sector.

### 3.4.1.4. Other recent developments

Other recent developments in the upstream subsector include a successful raise of KES 11.4b (US$ 12.78m) capital by Africa Oil in February 2015 most of which will be used for exploration on its Kenyan blocks. National Oil Corporation of Kenya (NOCK) also announced its intention to raise US$ 2b via debt, internal sources and new equity, to exercise its back-in rights on 2 of its blocks i.e. Blocks 10BB and 13T. Furthermore, GoK has announced its intention to acquire 2.5% of the proposed 30,000 barrel refinery in Uganda, at an estimated cost of KES5.6b (US$ 6.28m), in line with East African Community (EAC) partner states' commitment to jointly contribute to the development of the Northern Corridor Integration Projects. Currently, the Ugandan Government is negotiating with a preferred bidder under the PPP framework under which it will hold a 40% stake in the project.

[9] Reuters, http://www.reuters.com/article/2015/02/17/us-markets-oil-idUSKBN0LL02T20150217, accessed 18 February 2015

GoK via KPC has delayed the signing of an agreement with Qatar Gas for the supply of 1 million mt/year of LNG following recent onshore gas discoveries in Block 9 by Africa Oil. GoK had planned a 700MW CCGT power plant at Dongo Kundu to be powered by the imported LNG; however the use of indigenous gas resources as feedstock is now under consideration as an alternative.

## 3.5. Overview of the power sector

With an estimated population of 45.01m, Kenya is the seventh most populous country in Africa and it has an electrification rate of 23%. The total installed generating capacity in Kenya as at 30 June 2014 stood at 1,885 MW – a 28% increase from the June 2010 of 1,473 MW. The country's power sector has over the years seen a number of improvements and added initiatives in line with the Government's objectives to increase power supply and penetration. With this in mind, the peak load is projected to grow to 2,673 MW by the end of 2015.

According to Business Monitor International, power generation is expected to increase by 12.2% year on year in 2015 to 10.6m MWh, and by more than 123% over the long term reaching 20.6m MWh in 2023. Power consumption on the other hand is expected to increase by 11% year on year from 9.2m MWh in 2015 to 17.8m MWh by 2023 (The Least Cost Power Development Plan (LCPDP),2011 projected average annual consumption growth of c.13%). A steady increase in capacity implies a shift from the import to the export of electricity. Kenya Power (KPLC) is currently exporting electricity to Uganda and Tanzania and in December 2014 entered into an agreement to sell 30 MW of power to Rwanda.

Sector development initiatives by the Government as well as KPLC are propelling the country closer to achieving its Vision 2030 goal of transforming Kenya into a newly industrialized middle income economy. By 2030 the Vision has set to gradually increase the installed electricity capacity to 15,000MW. To achieve an economic growth rate of 10% per annum by 2015 and sustain it until 2030, the electricity and energy infrastructure must be developed further for example in the power distribution and transmission network.

### 3.5.1. Sources of energy

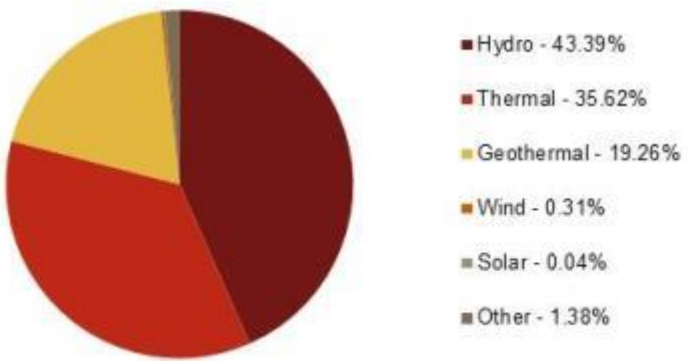
KPLC has supported industrial sectors by developing the most well-established power sector in sub-Saharan Africa. Since the mid-1990s for example, KPLC has run a small but successful independent power project (IPP) procurement program that has seen the total electricity generating capacity increase over the years.

The current sources of energy are tabled below:

*Table 3.3: Current power generation mix in Kenya*

| Source of Energy | Installed Capacity (MW) | Potential Capacity[10] | Commentary |
|---|---|---|---|
| **Hydro** | 817.81 | 3000-6000 MW | According to the LCPDP 2011 Report |
| **Thermal** | 671. 50 | - | Kenya imports c. 3.6m tonnes of coal annually (LCPDP 2011). There are however exploration activities being undertaken for potential local reserves. Thermal power generation is nevertheless reliant on the importation of coal and petroleum products. Potential thermal power generation to come online in the next few years include: Triumph power 83MW MSD, Lamu coal 982MW and Kitui coal 960MW |
| **Geothermal** | 363.00 | 5000-10000MW | According to the LCPDP 2011 Report |
| **Wind** | 5.90 | 346 W/m2 | Since Solar and Wind cannot be estimated in wholesome, the potential capacities have been based on the wind power and solar strength as per the analysis in the LCPDP. |
| **Solar** | 0.70 | 4-6 Kwh/m2/day | |
| **Other (Bagasse)** | 26.00 | 830 Gwh/year | According to the LCPDP 2011 Report |
| **Total** | *Installed Capacity as at 30 June 2014 = 1,884.91MW* | | |

*Figure 3.5: Distribution of the installed capacity by energy source*




*Source: Kenya Power Annual Report 30 June 2014, Least Cost Power Development Plan 2011*

The table above outlines the installed capacity as at June 2014 as documented in Kenya Power's 30 June 2014 annual report. The following additional capacities have since then been brought onboard: Thermal – 30.65MW and Geothermal – approximately 243.94 MW. Further to this nearly 20MW of Hydro power was shut down.[11]

[10] Least Cost Power Development Plan, LCPDP 2011 - 2031
[11] Ministry of Energy and Petroleum website (http://www.energy.go.ke/Projects.html)

KenGen has also commissioned an additional 45MW of Wind Power generation (i.e. Ngong Phase II), bringing the total installed capacity at the end of December 2014 to c. 2,184.5MW.

*Hydropower generation*

Hydropower is Kenya's largest source of power generation and contributed c.43.4% (817.81MW) as at June 2014, of the total installed capacity. With 9 major power plants, KenGen is the largest producer of hydropower in the country. In addition to this there are 5 smaller power plants and 2 IPPs.

According to Kenya's LCPDP, 2011 – 2030, the country has an estimated hydropower potential of between 3,000 MW to 6,000MW. The study has identified a potential of 1,449MW of power with an annual estimated production of at least 5,605Gwh per annum of energy. The current installed capacity of hydro implies this potential is yet to be exploited. See the table below for a break-down of the major hydro power potential.

*Table 3.4: Major hydropower potential*

| River Basin | Potential Capacity (MW) | Average Energy (GWh/yr) | Firm Energy (GWh/yr) |
|---|---|---|---|
| **Tana** | 570 | 2,490 | 1,650 |
| **Lake Victoria** | 295 | 1,680 | 1,450 |
| **Ewaso Ngiro North** | 155 | 675 | 250 |
| **Rift Valley** | 345 | 630 | 300 |
| **Athi Basin** | 84 | 460 | 290 |

*Source: Least Cost Power Development Plan: Study Period 2011 – 2030*

Kenya's over reliance on hydropower does not bode well for the country's energy sector. Vulnerabilities pegged to significant variations in rainfall have hampered the sector's performance as a result. These variations are partially attributable to climate change, effects of which have been seen over the last decade. As a result the Government is looking to diversify its energy sourcing programs by making use of alternative sources of energy so as to reduce electricity outages that are currently affecting the economy and create reliable electricity supply.

*Coal power generation*

In 2010 the Ministry of Energy and Petroleum (MoEP) discovered commercial coal deposits in the Mui Basin of Kitui County situated 180km north-east of Nairobi. The coal deposit is divided into Blocks A, B, C & D where Blocks A, B & D have coal in the 10 out of the 20 exploratory wells while Blocks C has been explored and is noted to have at least 400 million metric tons of coal reserves valued at KES 3.4 trillion (US$ 38.13m).

Blocks C & D have been mapped out and commissioned to Fenxi Industry Company from China while Blocks A & B are to be re-advertised. Further to this, 31 new blocks delineated outside the Mui Basin will soon be tendered. The Mui Coal plant, whose tender was recently awarded to Centum Investment Group, is scheduled to produce 960MW by 2016.The consortium comprising of Centum Investment Group and Gulf Energy is currently laying the ground for construction of the power plant.

In addition to the coal project, another 960MW is to be developed in Kilifi/Lamu County using imported coal. The proposed coal-fired power plant is part of the Government's plan to generate 1,920MW of electricity from December 2017.

*Geothermal power generation*

Geothermal energy accounted for 19.26% (approximately 363MW) of Kenya's total installed capacity (1,885 MW)[12] and as at 30 June 2014.Between June 2014 and December 2014, KenGen commissioned an additional c.243 MW of capacity at Olkaria (140MW each at Olkaria I and Olkaria IV). Unexploited geothermal resources were estimated to be between 7,000MW to 10,000MW in the Rift Valley alone. Due to the vulnerability of drought and high costs related to liquid fuel importation, the Government of Kenya has purposed to reduce the country's dependency on fossil fuels and hydropower by increasing the total electricity generating capacity from geothermal resources to 5,000 MW by 2030.

Geothermal power resources are set to be further developed by KenGen, Geothermal Development Company and Independent Power Producers. KenGen commenced its implementation plan to add more than 1,000MW between 2014 and 2018. GDC is also in various stages of geothermal steam development within the Rift Valley.

In addition, there are 3 more IPPs that have entered into Power Purchase Agreements (PPAs) with KPLC to commence the development of 3 x 35MW geothermal power plants on a 25 year Build Own Operate ("BOO") basis at Menengai Geothermal field in Nakuru, Kenya. This illustrates the Government's aim to partner with the private sector to achieve its plan to grow the total electricity generating capacity of the country.

*Wind and Solar power generation*

KenGen currently has a total installed capacity of 50.45MW (0.31%) sourced from a wind energy project located at a wind farm in Ngong site near a Nairobi. As part of the Rural Electrification Program, there is an additional 0.6MW of installed wind capacity.

According to WinDForce – wind energy experts who carried a study in Kenya in 2013 - the country has a significant potential for wind. Wind speeds of as much as 8 to 14 meters per second have been recorded in several areas across the country, such as Marsabit and Turkana, making wind-powered electricity production attractive on a commercial as well as an environmental level.

The Government is keen to boost its intelligence of the best wind sites in the country and did set up a total of 61 wind masts and data loggers to gather information over the last three years. The state plans to offer these sites to investors for wind power generation.

Currently, the Lake Turkana Wind Project (LTWP) in North Eastern Kenya which spans 40,000 acres aims to provide reliable, low cost wind power to the national grid and will be the largest single private investment in Kenya's history; at KES 76 b (US$ 852m). The wind farm is planned to be fully operational by 2016 and will provide the country's national grid with 300 MW of wind generated electricity.

As for Solar power generation, the Rural Electrification Program has a total installed capacity of 0.7MW while a number of independent producers are in various stages of developing and utilizing solar power technology for captive use as well negotiating PPAs for supply to the national grid.

## 3.6. Oil and Gas sector discussion

### 3.6.1. State of the upstream sub-sector

Despite the heightened activity in recent years, Kenya is still at preliminary stages in developing upstream activities; Tullow expects to finalise appraisal and testing of its Turkana oil finds by the end of 2015 to determine if the discoveries are commercially viable. Should this be the case, project approval for the development of a crude export pipeline would be the next major milestone that would facilitate a final investment decision to develop upstream production of oil.

In terms of gas, Apache's Mbawa-1 well drilled in 2012 did encounter non-commercial quantities of gas. Following this BG Group and its partners discovered oil and gas in offshore Lamu in 2014, however these resources have also been found to be unviable. As a result of the large natural gas finds in Mozambique and Tanzania, Kenya's coastal and offshore blocks have attracted significant interest. Pancontinental (one of BG's partners) reported that despite the 2014 finds being non-commercial, they were 'enthusiastic' about future gas

[12] Kenya Power 2014 Annual Financial report

and oil exploration in the offshore blocks. In mid-2014 Africa Oil discovered gas onshore on block 9 after drilling the Sala-1 well. According to Platts, it is estimated that there is potentially 1.8 Tcf of gas on this block[13].

Kenya is yet to conduct its first competitive bidding round for oil and gas blocks, which was originally slated for mid-2013 with 8 blocks on offer; however the ongoing policy review process led to this being postponed. To date the upstream sector remains characterised by smaller independent players, some of which have no producing assets. These firms will need to rely on equity raising and partnerships with large national oil and gas companies, for example Petronas in order to marshal the financial and technological capacity required to develop their blocks and reach commercial production.

Kenya and the wider region including Uganda, South Sudan, Ethiopia, Tanzania and Mozambique, has emerged as one of the most promising exploration regions over the past 10 years, according to Standard Bank's global head of oil and gas, Simon Ashby-Rudd during an interview by CNBC Africa; this implies that Kenya will need to compete for investment into the sector both internationally, and regionally against her neighbours. In conclusion, GoK will need to ensure that the appropriate structures are implemented to keep Kenya competitive in terms of attracting continued investment into the nascent upstream sub sector.

### *3.6.2. State of the Midstream & Downstream sub-sectors*

Kenya has a product pipeline system which is managed and operated by Kenya Pipeline Company (KPC), who transports petroleum products from Mombasa to inland areas. KPC has constructed a pipeline network, storage and loading facilities for the storage, transportation and distribution of petroleum products within the region. Once oil shipping companies dock at the Mombasa port, fuel is moved into the Kipevu oil storage facility and transported through the pipeline system passing through Nairobi, Nakuru, Kisumu, and Eldoret and exporting it to neighboring countries such as Uganda.

KPC is also responsible for overseeing quality control and certification on the oil products facilitating the fuelling of aircrafts through a hydrant system at Jomo Kenyatta and Moi International Airports as well as dispensing petroleum products for local and export markets.

Kenya Pipeline Company, established as a fully state-owned corporation has been planning to privatize its operations. However as per a recent announcement from the Privatization Commission made in February 2015, these plans have been put on hold to pave way for the expansion of the company's storage facilities amid the growing demand for petroleum products in East Africa. The commission said the sale would also await the outcome of the ongoing restructuring of State corporations.

The storage facilities project, with an approximate value of KES 4.8b (US$ 53.83m) involves building four storage tanks with a total capacity of 133.52 million litres – an equivalent of 22% of KPC's total national capacity of 612.32 million litres. At present, the Nairobi terminal with a capacity of 100.52 million litres is the second largest after Kipevu's 326.3million litre-facility[14]. This expansion of KPC's terminal in Nairobi will help address the current congestion at the Kipevu storage facility.

In addition, KPC recently awarded the tender for the construction of a new pipeline between Nairobi and Mombasa to Lebanon's Zakhem International. The key objective of this US$ 490m project is to replace the existing 14-inch pipeline, which has outlived its life span and is prone to ruptures, with a 20-inch diameter pipeline. The proposed pipeline is expected to be operational in 2016 and will be better suited to meet the projected demand for petroleum products in Kenya and the East African region for the next 30 years. The project will be financed through internally generated company funds and external borrowings from the World Bank.

The National Oil Corporation of Kenya is a state corporation owned by the Government of Kenya through a joint ownership by the Ministry of Energy and Petroleum and the National Treasury.

In the upstream, the corporation acts as a facilitator by marketing Kenya's exploration acreage, management of gas and exploration data and the running of the National Petroleum Laboratory. NOCK also operates its own exploration acreage in Block 14T located within the Tertiary Rift Valley Basin. Moreover, the corporation has developed and deployed a number of innovative products within the Liquefied Petroleum Gas (LPG) space[15].

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[13] Plats, McGraw Hill Financial (http://www.platts.com/latest-news/natural-gas/nairobi/kenya-delays-signing-lng-deal-with-qatar-on-domestic-26014268) accessed on 24 February 2014.
[14] Kenya pipeline company website (www.kpc.co.ke)
[15] National Oil Corporation of Kenya website (www.nationaloil.co.ke)

Furthermore, NOCK is also working on developing an offshore floating jetty technically referred to as a Single Buoy Mooring (SBM) as well as the establishment of Strategic Petroleum Reserves (SPR) which involves the construction of a modern large scale tank farm. Following a press release statement in February 2015, NOCK will be picking a transaction adviser for the proposed oil jetty in March 2015. The transaction adviser for the 280,000 dead weight tons capacity offshore jetty will help the state-owned oil marketer identify a strategic investor for the construction estimated to cost US$ 500m. In addition, the tank farm whose plans are still underway seeks to increase the country strategic oil reserves from the current 21 days to 90 days.

Oil marketing companies have a wide network of over 400 petrol stations serving various towns throughout the country. Of the most recognized oil marketing companies, Shell has a network of over 120 service stations, Total Kenya has a network of over 170 stations and NOCK has over 110 stations. At the time of this report, it was not possible to cite the exact number of petrol stations owned by small scale filing stations (independently owned downstream companies) with full certainty. The World Bank estimated the number of motor vehicles per 1000 people at 25 cars as at 2012. This translates to an approximate of 1,050,697 cars nationwide, since the population at the time stood at an approximate of 42 million people. A majority of the nation's cars are used and located within Nairobi, the country's capital city. As a result, the level of demand outweighs the supply within the transport sector and an increase in supply of petroleum would be in tandem with the increased demand.

## 3.7. Policy framework

### 3.7.1. Current policy framework

The major laws, policies, and guidelines governing Kenya's oil and gas sector are summarized in the table below and discussed in detail in Appendix C:

*Table 3.5: Major laws and policies- oil and gas sector*

| Policy | Major Provisions |
|---|---|
| **Vision 2030** | Vision 2030 was launched in 2008 as the national blueprint for the long term development of the country. Regarding the energy sector, the Vision states that "Energy is one of the infrastructural enablers" of the three pillars of Kenya's Vision 2030. The sector is expected to develop the energy policy, laws, regulations and infrastructure which are necessary to ensure that it plays its role for the country to meet the economic and social goals in the Vision. |
| **Constitution of Kenya(2010)** | The new Constitution of Kenya 2010 was promulgated in August 2010 and requires that all the existing policies, laws and regulations should be reviewed and amended to ensure that they are aligned with the constitution and that there are no ambiguities in the divisions of functions, powers and responsibilities between the National and County Governments. |
| **Sessional Paper No. 4 of 2004 on Energy** | Sessional Paper No. 4 of 2004 on Energy has been the policy guideline for the energy sector since 2004.The policy proposed the enactment of a new Energy Act, the establishment of a single regulatory body for downstream petroleum, electricity and renewable energy, the establishment of the Energy Tribunal among other legal and institutional changes. In particular the policy realized the need to separate some of the policy, regulatory and operational functions which were previously undertaken by the Ministry of Energy.<br><br>In the upstream petroleum sector the policy reinforced the Governments continued efforts to create an enabling environment for potential explorers and investors. |
| **The Energy Act(2006)** | The Energy Act 2006, was enacted following the formulation and adoption of Sessional Paper No. 4 of 2004.The Act transferred the licensing and regulatory mandate for downstream petroleum operations from the Ministry of Energy to the Energy Regulatory Commission (ERC) while retaining the policy making function with the Ministry. The Act also established the Rural Electrification Authority (REA) and the Energy Tribunal to hear and determine appeals on decisions made by ERC. The Act gives ERC, the powers for technical and economic regulation for |

| | |
|---|---|
| | downstream petroleum, electricity and renewable energy. |
| **The Petroleum (Exploration and Production) Act, Cap 308** | This Act which was enacted in 1986 has been the main law governing upstream petroleum activities in the country. The Act provides guidance on licensing of petroleum blocks, and allocation of oil blocks. All petroleum existing in its natural condition in strata lying within Kenya and the continental shelf is vested in the Government |
| **The Model Petroleum Production Sharing Contract ("PSC")** | The signed PSC is the legal framework which authorizes oil exploration companies to engage in petroleum operations within Kenya. It is the full legal relationship between the contractor and the Government in relation to the specific oil exploration block, specifying the rights and obligations of the parties. |
| **The Finance Act, 2014** | This Act was prepared to amend the law relating to various taxes and duties. The Finance Act, 2014 includes a rewrite of the Ninth Schedule ("the Ninth Schedule") of the Income Tax Act on the taxation of oil and gas (a detailed review is included below). |
| **Other Relevant Laws** | There are several other existing or draft laws which have either major or minor impacts on the energy sector. Among them are:<br><br>1. The Environmental Management and Co-ordination Act, 1999,<br>2. The Standards Act, Chapter 496.<br>3. Occupational Safety and Health Act, 2007 ("OSHA").<br>4. The Local Government Act, Chapter 265<br>5. The County Government Act<br>6. The Land Act 2012.<br>7. The Land Registration Act, 2012<br>8. The National Land Commission Act<br>9. The Natural Resources (Benefit sharing) bill, 2014<br>10. The Public Procurement and Disposal Act No. 3 of 2005<br>11. The Draft Energy Bill, 2014<br>12. The Draft Petroleum Exploration, Development and Production Bill, 2014<br>13. The Draft Petroleum Exploration, Development and Production (Local Content) Regulations, 2014<br>14. The Draft National Energy and Petroleum Policy<br>15. The Draft Model Production Sharing Contract, 2014<br><br>We discuss each of these draft laws in more detail later in this section. |

*Source: PwC Consortium Analysis*

### *3.7.1.1. Conclusion on the current policy framework*

The Petroleum (Exploration and Production) Act, the Regulations therein, and the Production Sharing Contract (PSC), have vested the policy, regulatory, participatory and operational mandates for all upstream petroleum operations with the Ministry of Energy and Petroleum. These three legal documents do not include adequate provisions to address critical issues for the development of a modern upstream oil and gas sector, in particular following the recent discoveries in Kenya.

**<u>Review of the Ninth Schedule of the Income Tax Act (as amended through the Finance Act, 2014)</u>**

The Finance Act, 2014 includes a rewrite of the Ninth Schedule (the Ninth Schedule) of the Income Tax Act. The rewritten Schedule took effect from January 2015.

The Schedule attempts to remove inconsistencies in tax provisions between Production Sharing Contract and the Income Tax Act.

Key changes to the Finance Act and the Ninth Schedule include the following:

- The Finance Act eliminates the withholding tax applicable to farm out transactions and share sale transactions. Furthermore with effect from January 2015, farm out transactions will be taxed based on net gains rather than on gross considerations as is the case currently.

- Tax losses from petroleum operations can now be carried forward indefinitely until the loss is fully utilised.
- The Schedule now includes provisions for ring fencing of blocks where expenditure for a particular block can only be offset against income from that block in line with the model PSC.
- Capital expenditure incurred during the exploration stage is allowable for 100% capital deduction in the year which the expenditure is incurred.
- Interest, royalties and management fees payable by a branch of a petroleum company to its head office are no longer tax deductible.

*Table 3.6: Impact of the current tax environment on investment*

| Item | Key Characteristics / Impacts |
|---|---|
| **VAT Remission/ Exemption** | • Current VAT Act, 2014, exempts VAT on goods supplied to the sector. However, VAT (16%) now applies on services (previously a remission was in place).<br>• Current players can continue to exercise existing 5 year VAT remissions until expiry, unless they undertake a farm out transaction. In the event of a farm out occurring, or new players taking up licenses, VAT on services will apply immediately.<br><br>The new provisions effectively exclude services from VAT exemption. Furthermore, as a result of the move from a VAT remission to a VAT exemption on goods (only), suppliers cannot get an input tax credit for goods supplied and are likely to add the cost of the 'lost' tax credit onto the cost of goods. |
| **CGT on Share Sales – Upstream Exploration Activities** | • Taxed on net gain (based on initial acquisition cost and equity invested). However, no relief on exploration costs if funded by intercompany loans.<br>• There is no relief as other countries have.<br>• Seller has an **obligation** to inform KRA if there is any change in underlying ownership of more than 10% whether the transaction occurs offshore or not.<br>• Only have a tax obligation if value of Kenyan asset(s) is 20% or more of total company value.<br><br>CGT for oil and gas companies is charged at the applicable corporate income tax rate (30% for residents and 37.5% for non-residents). |
| **Taxation on Farm – Outs** | • Buyer gets relief for reimbursable of costs and **work obligations** undertaken.<br>• Seller only taxed on income (premium). Reimbursable relating to the specific block being farmed out can be fully offset on income.<br>• CGT for oil and gas companies is charged at the applicable corporate income tax rate. |
| **Withholding Tax (WHT) on Natural Resource income & royalties** | • Targets royalty type income from oil and gas and mining, however as currently phrased, WHT could apply to sale of petroleum or farm out transactions.<br>• This brings about a new level of taxation as the underlying income has already been subjected to Farm-Outs provisions and/or Capital Gains Taxation.<br><br>Rate of tax on royalties is 5% for residents and 20% for non-residents. Covers oil and gas, and mining. |

| Item | Key Characteristics / Impacts |
| --- | --- |
| **Subcontractor WHT** | • Also mobilization, de-mobilisation and reimbursement payments are subject to withholding tax.<br><br>Administratively challenging as different procedures are required for different types of subcontractors. |
| **Income Tax in the PSC** | • There is a significant difference between the existing PSCs and the latest draft (March 2015) in the treatment of income tax. In the existing PSCs the Government is expected to pay the Contractor's income tax out of the Government's share of profit oil. However in the new draft, the contactor will be required to pay both the income tax and the dividend withholding tax while Government's share of profit oil has not been changed. |

*Source: PwC Consortium Analysis*

In conclusion, the newly implemented tax regime may make it more challenging to attract new exploration firms to Kenya. Combined with the impact of lower crude prices, Kenya's tax regime may have a negative impact on the share prices, particularly for independent exploration firms with operations in the country, and therefore their ability to finance future operations. Furthermore, CGT on share sales may hamper efforts by existing exploration firms to fund additional exploration and potentially development of assets by partnering with larger oil and gas firms.

### *3.7.2. Policy gaps and comparability to benchmark countries*

The following are the major policy and regulatory gaps noticeable from comparing the practices in Kenya and other benchmark countries, namely Ghana, Nigeria and Malaysia:

**1. Lack of Comprehensive upstream oil and gas policy**

Currently there is no comprehensive oil and gas policy in Kenya. The existing Sessional Paper No. 4 on Energy has very little coverage on upstream petroleum operations and nothing at all on gas. The lack of such policy can partly be explained by the fact that until the first crude oil discoveries in 2012, the country was viewed as a frontier area for hydrocarbon resources and therefore there was no urgency in developing a comprehensive policy. The recent discoveries have created an urgent need for the development of a comprehensive oil and gas policy for Kenya.

**2. Division of Sector Roles**

The sectorial roles of policy formulation, regulation, operations and state participation in Kenya are all vested with the Cabinet Secretary. In two of the countries studied in our benchmarking for policy and legal frameworks, policy making and regulation are undertaken by different institutions. In Ghana, the Ministry makes policy while the mandate for upstream regulation was vested originally with the Ghana National Petroleum Corporation until 2011, when a new Petroleum Commission was established by an act of Parliament. Malaysia had a similar experience where PETRONAS has been the regulator since 1974.

There is need to establish a specific functional and legal unit to take over regulatory roles from the Ministry. In addition there should be consideration to possibly delink the operational and state participation roles from the Ministry. The fact that both Ghana and Malaysia established such units early may have been factors in the quick development of the resources after commercial discoveries were made.

**3. Environmental, Health and Safety Practices and Standards**

Both the Petroleum Act and the PSC do not explicitly require contractors to meet the national and international Environmental, Health and Safety (EHS) practices and standards before, during and after the petroleum operations. There are no requirements to prepare and undertake an Environmental and Social Impact Assessment (ESIA) or to establish and implement an Environmental Management Plan (EMP) as required by the Environmental Management and Co-ordination Act, 1999 and the Environmental (Impact Assessment and Audit) Regulations 2003. The PPP Act, 2013, however does require an ESIA to be undertaken for all projects developed within its purview. There is need for the new petroleum policy (currently under debate in Parliament) to explicitly require adherence to national and international environmental, health and safety laws and standards.

### 4. Revenue Sharing Procedures

The current policy, law and regulations do not provide for revenue sharing procedures as required by the Constitution of Kenya, 2010. The energy sector's policies and laws should be revised to bring them in tandem with the constitution and other laws regarding revenue sharing between the National Government, County Governments and the local communities. Currently, The Natural Resources (Benefit Sharing Bill), 2014 is under debate in parliament and the current draft proposes a formula for revenue sharing between National Government, county Governments and local communities. There is need for energy sector specific legislation to be harmonised with this policy if enacted.

### 5. Local Content Policy

Local content is a major issue in countries with upstream oil and gas operations. Nigeria enacted the Nigerian Oil and Gas Industry Content Development Act in 2010 and in Ghana a local content Act was enacted in 2014. Kenya can greatly benefit from developing an explicit policy and law in the early stages of oil and gas development so that local content can grow simultaneously with the industry. The current initiatives to develop and implement Local Content legislation should be fast tracked. Such policy and law should facilitate progressive growth in local content in line with industry growth and local capacity, while establishing mechanisms to speed up the development of national capacity to meet international industry standards. Local content regulations should also be designed to take on a national outlook, rather than solely a local community view.

### 6. Competitive Bidding for Petroleum Blocks

The current licensing procedures do not require the calling of public bids for available petroleum blocks. While this worked well in the past when the country was viewed as having limited or no hydrocarbon potential, recent discoveries in the country and the region have changed the scenario. The country should now develop procedures and methods for calling open competitive tenders for available oil blocks.

### 7. Gas Law

The process of development and exploitation of natural gas, after discovery, is different from that for liquid petroleum. The three countries used in the benchmarking have created different structures to address this specific issue. Malaysia enacted a Gas Supply Act in 1993 while Ghana has developed both a gas policy and law to address the specific requirements necessary for development of natural gas. In the medium term Kenya should develop a gas policy and laws together with the institutional framework to facilitate early and prudent exploitation of any gas discoveries.

### 8. Midstream Operations

The Energy Act, 2006, vested technical regulatory powers for refining, storage and pipelines facilities with the ERC. However the law does not cover economic regulation of such operations particularly on issues like third party access to existing facilities and tariff setting. To help address these issues, The Energy (Operation of Common User Petroleum Logistics Facilities) Regulations, 2011 were drafted. However, these regulations are yet to be finalized and put into operation.

To enable optimum utilisation of investments in petroleum infrastructure, reduce entry barriers and enhance competition, the Energy Act should be revised to empower ERC (or any other institution) to undertake economic regulation of such facilities.

## 3.7.3. Proposed policy (drafts under parliamentary debate)

**Introduction**

The existing policy and regulatory frameworks for the upstream and downstream petroleum sub-sectors in Kenya are currently undergoing major reviews. There are three developments which have made such major reviews both necessary and urgent at this time.

1. In 2008, a new national development policy for Kenya, Vision 2030 was launched in which energy was recognised as one of the infrastructure enablers necessary for the achievement of the policy. The energy sector was therefore expected to amend its existing policies, laws, regulations and the institutional frameworks to ensure that they play their roles for the country to meet the economic and social goals stated in the Vision.
2. The new Constitution of Kenya, 2010, was promulgated in August 2010, bringing in major changes in the legal, governance and institutional structures in the country. The new constitution has created new institutions which are expected to enhance the participation of citizens in the decision making processes. It has created two levels of Governments, the National and County Governments, and separated the roles and functions of each level. The constitution requires that all the existing policies, laws and regulations should be reviewed and amended to ensure that they are aligned with the constitution and that there are no ambiguities in the divisions of powers and responsibilities between the two levels of Government.
3. Although Kenya has had a fairly developed downstream petroleum sector for many years, the upstream petroleum operations have been limited to the exploration phase only. However in 2012, crude oil was discovered in Block 10BB in Turkana County. Since then there has been more discoveries of crude oil and natural gas in Northern Kenya and natural gas offshore and in the Lamu Basin. This has created increased interest in exploration blocks in the country and has attracted independent producers as well as international oil companies. This changed outlook in upstream oil operations has increased the need to review the existing policy, legal and institutional frameworks in the sub sector.

Currently there are five policies, legal and regulatory documents which are under development in Kenya for the energy sector. The latest drafts were published on October 11, 2014 and on 20th January 2015. A detailed review is included in Appendix D.

1. Draft National Energy and Petroleum Policy- 20th January ,2015 Edition
2. Draft Energy Bill, 2015- 20th January 2015 Edition,;
3. Draft Petroleum Exploration, Development and Production Bill, 2015- 20th January 2015 Edition;
4. Draft Model Production Sharing Contract-20th January 2015 Edition
5. Draft Petroleum Exploration, Development and Production (Local Content) Regulations, 201411th October 2014 Edition

### 3.7.3.1. Conclusions on the proposed policy

The new Draft Petroleum Exploration, Development and Production Bill 2015 (20th January 2015 issue) has attempted to address the grey areas in the earlier Draft Energy Bill 2014 regarding the roles of the Cabinet Secretary, National Upstream Petroleum Advisory Committee, the Energy Regulatory Commission and the Upstream Petroleum Regulatory Authority (UPRA) in upstream petroleum operations.

The proposed Petroleum (Exploration, Development and Production) Amendment Bill 2015 has captured most of the policy and regulatory gaps identified in the 'Policy issues' section above. The setting up of UPRA is a positive development in separating and defining sector roles better. There are attempts to address such issues as local content, health and safety, environmental compliance and others in more detail. The draft is still undergoing interrogation by the relevant groups in Government.

In conclusion, the ongoing legislative framework review is a progressive step that will enable Kenya to fill in gaps in the existing framework governing oil and gas.

### 3.7.4. Recommendations

1. In section 8(1) of the Draft Petroleum Exploration, Development and Production Bill, 2014; it states that ***"no person shall engage in any upstream petroleum operations in Kenya without having previously obtained the permission of the Cabinet Secretary and/or Authority in such manner, in such form and on such terms as are prescribed by this Act and by regulations made thereunder"***. The inclusion of the words "and/or Authority" should be reviewed as it can cause a major conflict. It is recommended that the mandate for permitting upstream operations be vested only in the Cabinet Secretary.

2. There is need to differentiate more clearly the roles of both ERA and UPRA in the economic and technical regulation of midstream infrastructure facilities for crude oil and gas. Section 17(s) of the Draft Petroleum Exploration, Development and Production Bill, 2014 gives this role to UPRA while section 12(b) of the draft Energy Bill assigns a similar role to ERA. To ensure more independence in regulating these facilities it is recommended that this role be vested in ERA.

3. Local Content is an emotional issue both socially and economically. The Draft Petroleum Exploration, Development and Production (Local Content) Regulations, 2014 is a first step in the right direction. However the draft is too prescriptive in the initial periods instead of enabling local content to grow in tandem with the development of upstream operations. Some of the percentage target local content requirements are difficult to achieve in the initial stages. For example under section 21, contractors are expected to have research plans and budgets before commencement of petroleum operations. It is recommended that a local content policy, be developed with full stakeholder participation, before any legislation is enacted.

# *Upstream Oil & Gas Sector*

# 4. Upstream Oil & Gas Sector

**CAVEAT**

Our views and projections of oil and gas supply potential should be treated as indicative for the purposes of this Study. Resource and supply estimates provided should be considered as high level and not a result of a technical study into reserves and production of reserves.

Extended well testing is currently being undertaken by some operators in conjunction with GoK. Results are expected in 2015 but have not been taken into account in this Study. Furthermore, a detailed geological study on oil and gas resource potential has yet to be undertaken by GoK.

Equally, the recent downturn in global crude oil prices may have an impact on the ability of companies to invest in the short term. We have not considered the impact of such uncertainties on the timing assumed for first oil and gas production as first oil and gas production is still at least a number of years away and the collapse in crude oil prices is seen by most to be a result of imbalances between supply and demand in the short to medium term.

We understand that there are still uncertainties surrounding upstream investment and discussions are on-going between the GoK and upstream players as to fiscal and other terms that might apply. Discussions can take several years before agreement is reached and this would inevitably impact on timing and the level of oil and gas production in Kenya. For the avoidance of doubt, advising on upstream and fiscal terms is not a part of this Study.

Equally, the recent downturn in global crude oil prices may have an impact on the ability of companies to invest in the short term. Although this could potentially impact on the timing assumed for first oil and gas production, given that for Kenya this is still some years away and the collapse in crude oil prices is seen by most observers to be a result of imbalances between supply and demand in the short to medium term, we consider the effect on the Master Plan to be minimal.

The activities in this Study are related only to onshore areas of Kenya and those areas offshore that are not under dispute. The Study Area is therefore defined to exclude any disputed areas, whether onshore or offshore. As a consequence, none of the activities carried out are expected to be the subject of a dispute between Kenya and any of its neighbouring countries.

## 4.1. Introduction and Approach

The purpose of this section is to provide an insight into the likely distribution and potential availability of hydrocarbon resources in Kenya. However, Kenya is still in the early stages of exploration activity with initial or test wells being drilled only in a few license blocks. Hence, 1) oil and gas resource estimates may increase if and when exploration activity and drilling increases, and 2) it is not possible to provide an accurate view on oil and gas resources for current discoveries until further exploration and drilling takes place.

We have nevertheless developed scenarios for Kenyan oil and gas resources in order to consider midstream and downstream infrastructure planning. Our Base Case estimates have been formed through high level discussions with operators who are actively exploring in the different exploration basins. For operators who declined to provide views, we have relied on publicly available data or, if no such data was available, we have not included resource estimates from these license blocks.

The term "resources" is used to describe potential reserves, as the term "reserves" (whether proven, probable or possible) is frequently used to refer to discovered hydrocarbons. Only some of the resource potential being considered can be classed at probable (P50[16]) reserves. Given the large amount of uncertainty around this, and being beyond the purposes of this Study, we do not attempt to distinguish between resources and reserves or try to risk such resource levels.

[16] Industry specialists refer to Probable reserves as "P50", having a 50% certainty of being produced. These reserves are also referred to in the industry as "2P" (proven plus probable).

We used the scenarios developed on potential resource in each basin to provide high level estimates of oil and gas production profiles out to 2040 using general industry rules of thumb for estimating production from a given field. We then used these production profiles to consider the potential development of midstream and downstream projects and infrastructure outlined later in this Study, and to consider at a high level the policy implications to enable such investments.

It should be stressed that the aim of the Study is to develop scenarios on supply potential out to 2040 and not to carry out a field development plan for resources that are more likely to be produced. Being land-locked, there is potential for crude oil production from Uganda and South Sudan to be exported via Kenya. For the purposes of this Study we only look to estimate potential pipeline capacity required by these countries for transit volumes and not estimate total production levels as has been undertaken in respect of Kenya.

## 4.2. Data Availability

The intention of this task is to provide insight on Kenya's oil and gas supply potential using publicly available information supported by confidential reports provided by the MoEP, and confidential conversations with a number of exploration companies active in Kenya.

Little information was available from the MoEP and NOCK, other than the information available on NOCK's website, which includes four studies that document the petroleum potential of Kenya with the latest study being undertaken in 2001.[17] As this information is quite dated now and much more exploration activity has taken place more recently, these reports have not been taken into account. Updates of supply potential were requested by the PwC Consortium but may only be made available during 2015 once extended well testing and analysis has been completed.

The production sharing contracts used in Kenya entitle the Kenya Energy Ministry to receive detailed technical reports from oil companies operating within Kenya[18]. However, no information has been provided by the Ministry to the PwC Consortium on this as yet. The kind of information included in such reports would be:

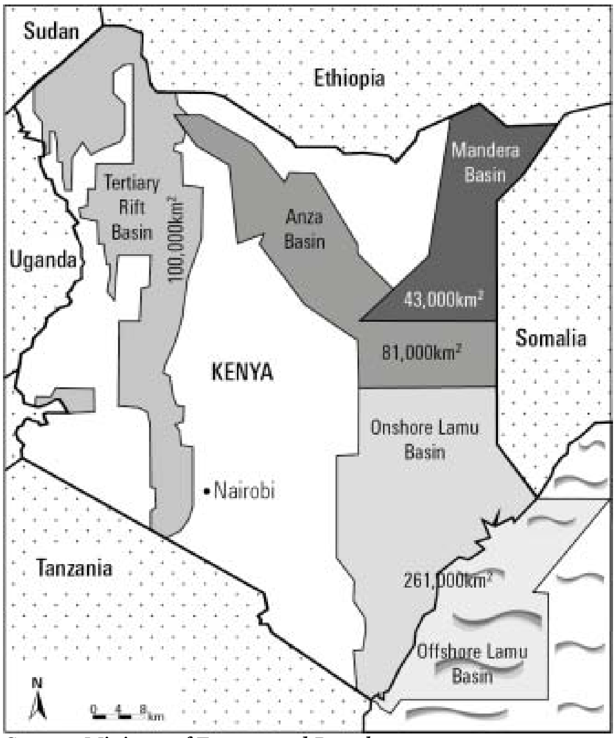
- Drilling programmes, and work programmes and budgets;
- Details of geophysical surveys;
- All geological and geophysical information and data obtained by oil companies operating within Kenya together with interpretations and logs;
- Rock samples and well samples;
- Regular summaries of petroleum operations including drilling and production reports and reports on seismic data operations;
- Notification of discoveries together with a report on the discovery and its commerciality and economic evaluation; and
- In the event of a gas discovery, gas market studies showing potential gas markets, volumes that can be supplied to such markets and the infrastructure required to supply such gas volumes.

Despite recent levels of exploration activity and a number of discoveries, Kenya is still very much a frontier exploration player. Exploration companies are largely in the early stages of exploration, with many companies still evaluating the results of airborne and seismic surveys in order to define and plan their exploration drilling programmes. It will be some years before the level of exploration in Kenya reaches a point where the potential resource can be regarded as firm.

NOCK has identified four large sized sedimentary basins that straddle the country. These are Lamu, Anza, Mandera, and Tertiary Rift (or East African Rift) basins. The sedimentary basins are divided into exploration blocks as shown below.

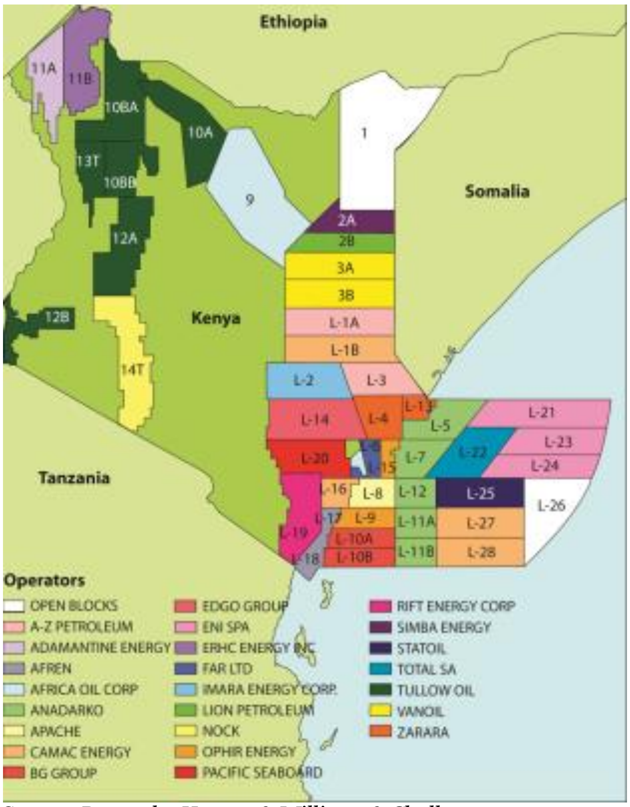
[17] http://nationaloil.co.ke/site/3.php?flag=upstream&id=6
[18] Source is the model PSC provided by NOCK via their website

*Figure 4.1: Kenya basins structural framework*




*Source: Ministry of Energy and Petroleum*

*Figure 4.2: Kenya exploration blocks*




*Source: Report by Hunton & Williams & Challenge energy*

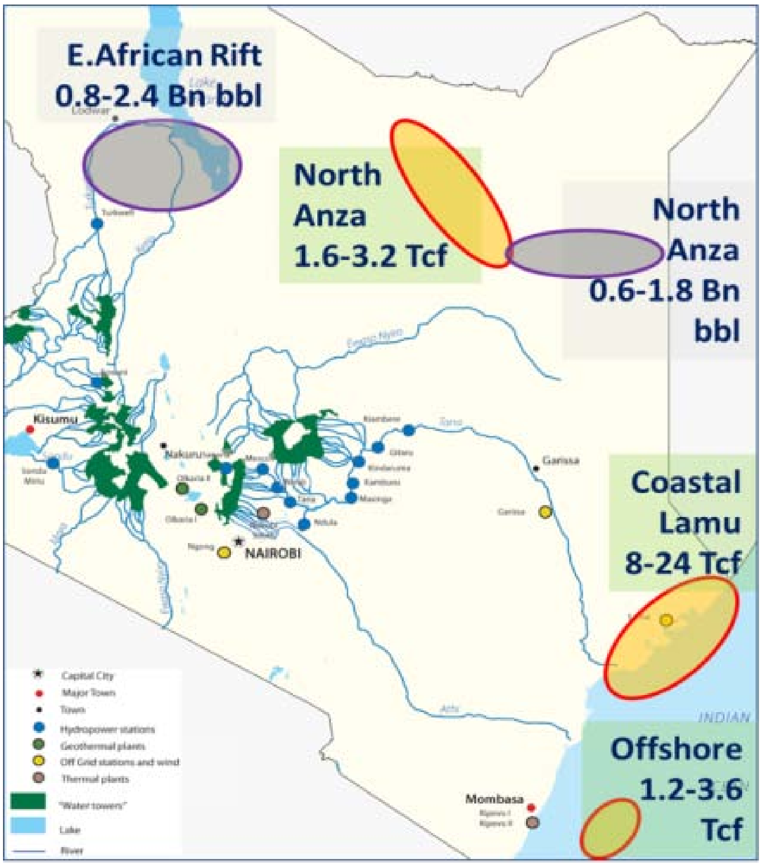
## 4.3. Estimated Resource and Supply Potential

Over the last five years considerable exploration activity has taken place with some 11 wells being drilled in total by the end of 2013 – the majority of which were by Tullow Oil in the East African Rift. Exploration activity was set to increase further in 2014 with around 20 wells planned. Although it is very early to be definitive, the discoveries to date have been gas in offshore areas and the Anza Graben with oil discovered in the East African Rift. A summary of exploration activity and resource potential for each of the areas is provided in Appendix E.

Out of the four basins, the East African Rift has proved to be the most successful. So far seven discoveries have been made and Tullow Oil estimates the resource potential at over 600 million barrels of oil, with the possibility that it will exceed 2 billion barrels of oil. Coastal/Offshore areas have also proved an exploration success. One discovery was a blow out in 1970 when BP/Shell drilled into an over-pressured gas reservoir. Probable remaining reserves are estimated at around 1 trillion cubic feet of gas. Flow Energy (FAR Ltd) has also identified three prospects with a total unrisked potential of around 1.5 trillion cubic feet of gas. Until recently exploration in the Anza Graben had yet to deliver a successful discovery, however, this changed when Africa Oil announced they had discovered around 2 trillion cubic feet of gas in Block 9 onshore. In Mandera, Lion Petroleum has identified leads and estimate total potential of over 1.5 billion barrels of oil.

Based on the data collated and discussed with different players as outlined above, we have developed the following Base Case to High Case ranges for potential oil and gas resource in place as shown in the figure below. Gas resource estimates are shown in Trillion cubic feet (Tcf) and oil resource estimates are shown in Billion barrels (Bn bbl).

*Figure 4.3: Oil and gas resource estimates*




*Source: PwC Consortium Analysis*

Estimates of Recoverable Reserves and Supply Profiles using the Base Case Resource Potential scenario are shown below. We assume a recovery factor of 40% for oil resource and 80% for gas resource. Dates for first production have been estimated and discussed with different players as shown below. High Case scenarios of Recoverable Reserves and Supply Profiles are provided in Appendix E.

*Table 4.1: Base case resource estimate*

| Basin | Type of Hydrocarbons | Estimated Resource in Place | Assumed Recovery Factor | Recoverable Reserves (bbl/boe*) | First Production |
|---|---|---|---|---|---|
| **East African Rift** | Oil | 2 billion bbl | 40% | 800,000,000 | 2018 |
| **Anza Graben (oil)** | Oil | 1.5 billion bbl | 40% | 600,000,000 | 2019 |
| **Anza Graben (gas)** | Gas | 333 million boe (2.0 Tcf) | 80% | 266,400,000 | 2020 |
| **Coastal Lamu** | Gas | 1.5 billion boe (10 Tcf) | 80% | 1,200,000,000 | 2020 |
| **Offshore** | Gas | 250 million boe (1.5 Tcf) | 80% | 200,000,000 | 2020 |

*Boe – Barrel of Oil Equivalent

*Source: PwC Consortium*

Supply profiles have been produced using general industry rules of thumb. We have assumed a well with initial production potential of 8,000 boe per day. Wells are assumed to decline in productivity following a standard exponential decline curve. An exponential decline curve is a technique used to forecast future production rates starting from an initial production rate with assumed parameters of the rate of decline using a curve derived from an equation of the form $y_t = y_{t-1}e^{-xt}$ where y is the production rate at time t, and x is the decline rate.

A template field for each basin has been created with the number of wells required to produce the recoverable reserves. Production is capped at a plateau rate assumed to last 9 years (approximating to in-fill wells being drilled to maintain initial production rates). In the scenarios listed below where multiple fields are assumed, the template field is applied incrementally, so for example where the first field is assumed to start in year 1 and a second field is assumed to start production in year 3, the basin production rates will be as follows:

*Table 4.2: Example of basin production rates*

| | |
|---|---|
| **Year 1** | Production rate for Year 1 of the template field |
| **Year 2** | Production rate for Year 2 of the template field |
| **Year 3** | Production rate for Year 3 of the template field<br>plus<br>Production rate for Year 1 of the template field |
| **Year 4** | Production rate for Year 4 of the template field<br>plus<br>Production rate for Year 2 of the template field |
| **Etc.** | |

*Source: PwC Consortium*

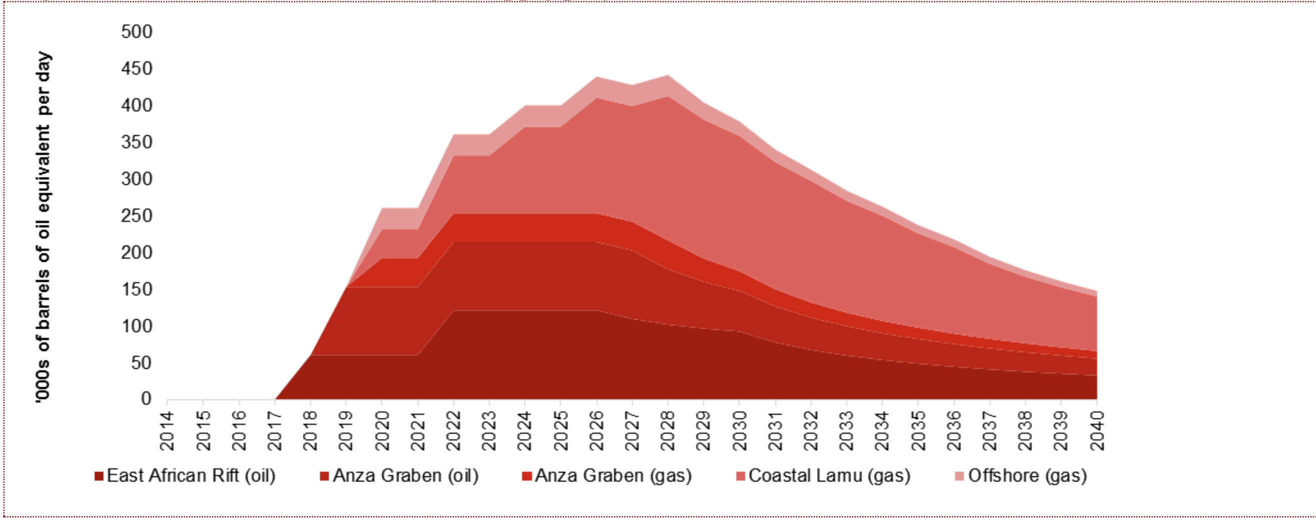
Base case oil and gas resource development assumptions and assumed supply profiles are shown in the table and figures below.

*Table 4.3: Base case reserves development assumptions*

| Basin | Developments | Timing |
|---|---|---|
| **East African Rift** | 2 x 1 billion bbl oil field | 2nd field is assumed to start production 5 years after the first field |
| **Anza Graben (oil)** | 1 x 1.5 billion bbl oil field | |
| **Anza Graben (gas)** | 1 x 2 tcf gas field | |
| **Coastal Lamu** | 5 x 2 tcf gas field | 2nd and subsequent fields are assumed to start production on alternate years |
| **Offshore** | 1 x 1.5 tcf gas field | |

*Source: PwC Consortium*

*Figure 4.4: Base case total oil and gas supply profiles*




*Source: PwC Consortium Analysis*

*Figure 4.5: Base case oil supply profiles*

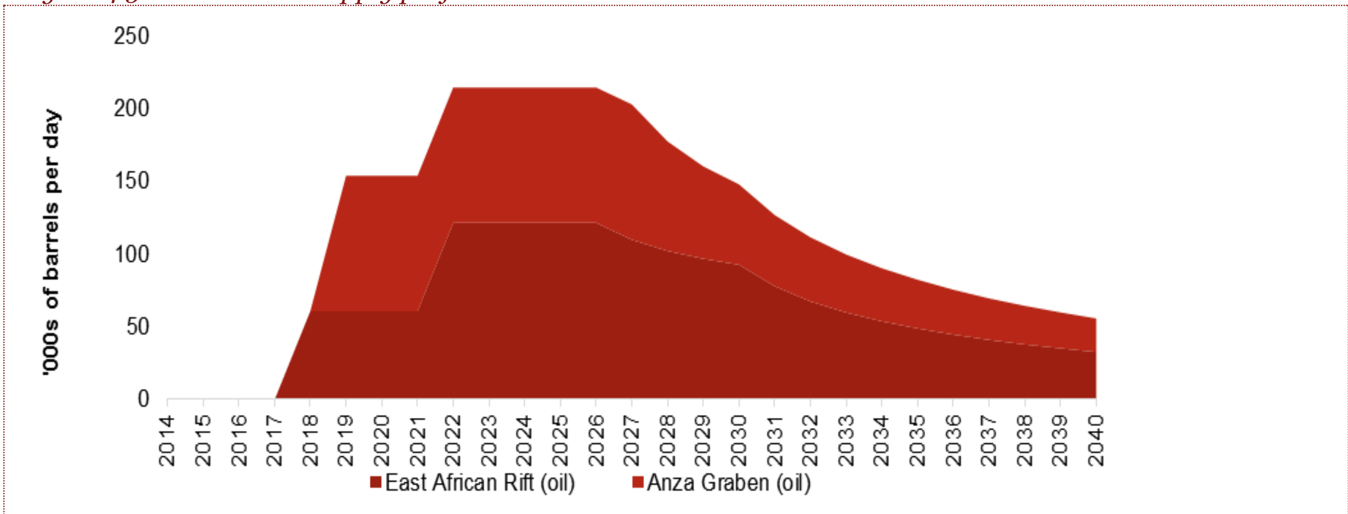
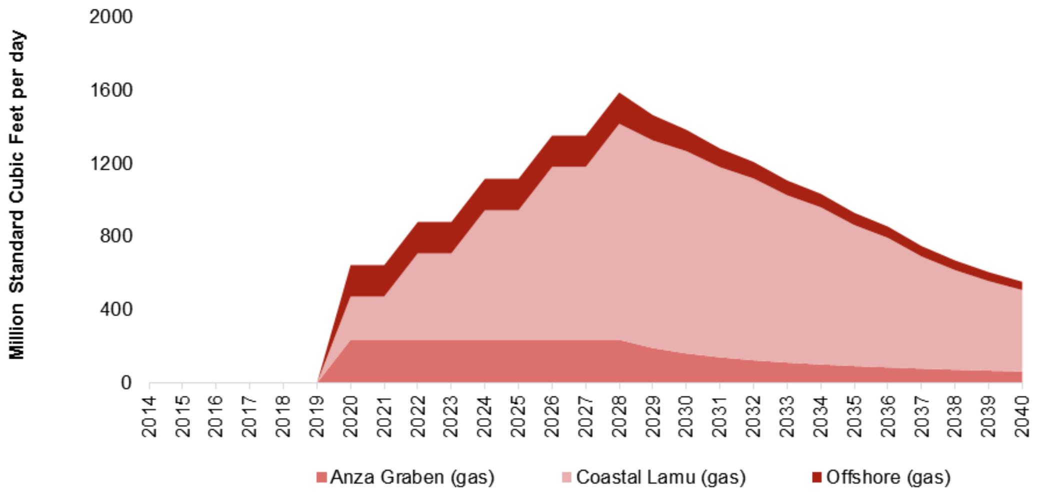


*Figure 4.6: Base case gas supply profiles*




*Source: PwC Consortium Analysis*

*Table 4.4: Base case oil and gas profiles*

| Base Case | East African Rift (oil) | Anza Graben (oil) | Total Oil | Anza Graben (gas) | Coastal Lamu (gas) | Offshore (gas) | Total Gas |
|---|---|---|---|---|---|---|---|
| | BBL/d | BBL/d | BBL/d | MMScfd | MMScfd | MMScfd | MMScfd |
| **2018** | 60,800 | | **60,800** | | | | |
| **2019** | 60,800 | 93,000 | **153,800** | | | | |
| **2020** | 60,800 | 93,000 | **153,800** | 236 | 236 | 172 | **644** |
| **2021** | 60,800 | 93,000 | **153,800** | 236 | 236 | 172 | **644** |
| **2022** | 121,600 | 93,000 | **214,600** | 236 | 473 | 172 | **881** |
| **2023** | 121,600 | 93,000 | **214,600** | 236 | 473 | 172 | **881** |
| **2024** | 121,600 | 93,000 | **214,600** | 236 | 709 | 172 | **1,117** |
| **2025** | 121,600 | 93,000 | **214,600** | 236 | 709 | 172 | **1,117** |
| **2026** | 121,600 | 93,000 | **214,600** | 236 | 946 | 172 | **1,354** |
| **2027** | 110,000 | 93,000 | **203,000** | 236 | 946 | 172 | **1,354** |
| **2028** | 102,300 | 75,200 | **177,500** | 236 | 1,182 | 172 | **1,590** |
| **2029** | 96,900 | 63,500 | **160,400** | 191 | 1,136 | 139 | **1,466** |
| **2030** | 92,800 | 55,200 | **148,000** | 161 | 1,107 | 117 | **1,385** |
| **2031** | 78,000 | 48,900 | **126,900** | 140 | 1,040 | 102 | **1,282** |
| **2032** | 67,600 | 44,000 | **111,600** | 124 | 995 | 91 | **1,210** |
| **2033** | 59,900 | 39,900 | **99,800** | 112 | 916 | 81 | **1,109** |
| **2034** | 53,900 | 36,400 | **90,300** | 101 | 860 | 74 | **1,035** |
| **2035** | 49,000 | 33,500 | **82,500** | 92 | 772 | 67 | **931** |
| **2036** | 44,800 | 30,800 | **75,600** | 85 | 709 | 62 | **856** |
| **2037** | 41,100 | 28,500 | **69,600** | 79 | 614 | 57 | **750** |
| **2038** | 38,000 | 26,500 | **64,500** | 73 | 545 | 53 | **671** |
| **2039** | 35,300 | 24,700 | **60,000** | 67 | 490 | 49 | **606** |
| **2040** | 32,800 | 23,000 | **55,800** | 62 | 446 | 46 | **554** |

*Source: PwC Consortium*

As shown in the table below, total estimated crude oil production of around 200 thousand barrels per day (k bbl/day) and total estimated gas production of around 1,300 million standard cubic feet per day (MMScfd) at plateau is much below oil and gas production in other more developed oil and gas producing nations. Nevertheless, as mentioned Kenya is still at early stages of exploration and more resource may be discovered if and when exploration activity increases.

*Table 4.5: Comparison to other oil and gas producing countries (2013 data)*

| 2013 Oil production - k bbl/day | | | 2013 Gas production - MMScfd | |
|---|---|---|---|---|
| **Angola** | 1,801 | | **Brazil** | 2,063 |
| **Egypt** | 714 | | **Peru** | 1,180 |
| **Libya** | 988 | | **Trinidad** | 4,145 |
| **Nigeria** | 2,322 | | **Norway** | 10,521 |
| **Malaysia** | 657 | | **UK** | 5,528 |
| **Kazakhstan** | 1,785 | | **Algeria** | 7,605 |
| **Norway** | 1,837 | | **Egypt** | 5,425 |
| **UK** | 866 | | **Nigeria** | 3,490 |
| **Oman** | 942 | | **India** | 3,258 |
| **Algeria** | 1,575 | | **Malaysia** | 6,681 |

*Source: PwC Consortium, BP Statistical Review 2013*

## 4.4. Estimated costs of production

It should be stressed that these estimates are not the result of a technical or engineering study and only aim to provide a high level indication of costs of production. Cost estimates will differ depending on the specifics of each field and will only be known much closer to the time of production. Such information may be provided by the operators as part of the terms of the production sharing contracts. However, given that Kenya is still in early stages of exploration, costs of production are still largely unknown.

For the purposes of this Study, costs of production have been estimated for single template field developments in each basin based on the number of wells, a central processing facility, ancillary processing facilities, infield pipelines and (for offshore fields) a jacket. Operating costs are assumed to be 10% of total capital expenditure. These template development schemes are set out in the table below:

*Table 4.6: Template development schemes for the costs of production*

| US$ million | | East Africa Rift | | Anza Graben Oil | | Anza Graben Gas | | Lamu Coastal | | Offshore | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Unit cost | No. units | Total cost | No. units | Total cost | No. units | Total cost | No. units | Total cost | No. units | Total cost |
| **Wells** | $30 | 18 | $540 | 27 | $810 | 12 | $360 | 12 | $360 | 9 | $270 |
| **CPU** | $500 | 1 | $500 | 1 | $500 | 1 | $500 | 1 | $500 | 1 | $500 |
| **Other Processing** | $250 | 1 | $250 | 1 | $250 | 0 | $0 | 0 | $0 | 0 | $0 |
| **Infield pipelines** | $250 | 1 | $250 | 1 | $250 | 1 | $250 | 1 | $150 | 1 | $150 |
| **Jacket** | $500 | 0 | $0 | 0 | $0 | 0 | $0 | 0 | $250 | 1 | $250 |
| | | | **$1,540** | | **$1,810** | | **$1,110** | | **$1,260** | | **$1,170** |

*Source: PwC Consortium*

Using these costs, the template field production forecasts discussed earlier and discounting costs and revenues over the period 2015 to 2040, a breakeven "plant gate" price range is estimated for each template field below:

*Table 4.7: Breakeven "plant gate" price ranges*

| | **US$/bbl, US$/MMBtu** |
|---|---|
| East African Rift | 20 - 25 US$/bbl |
| Anza Graben Oil | 20 - 25 US$/bbl |
| Anza Graben Gas | 4 - 5 US$/MMBtu |
| Lamu Coastal | 4 - 5 US$/MMBtu |
| Offshore | 6 - 7 US$/MMBtu |

*Source: PwC Consortium*

We have assumed a cost of US$30m per well, but no doubt in reality there will be cheaper wells (especially onshore) and more expensive wells. For the purposes of this Study we have not differentiated between costs for onshore and offshore wells as offshore wells may not necessarily be more expensive. For example, an onshore well that is located in hard to access regions can cost more to develop than an offshore well and cost of infield pipelines are typically lower for offshore developments as it is generally easier to lay pipelines offshore than onshore.

## 4.5. Conclusions

In respect of Kenya's upstream oil and gas sector:

- Despite recent high levels of exploration activity and a number of discoveries, Kenya is still very much a frontier exploration play. Upstream companies active in Kenya are largely in the early stages of exploration, with many still evaluating the results of airborne and seismic surveys in order to define and plan their exploration drilling programmes. It will be some years before the level of exploration in Kenya reaches a point where the potential resource can be regarded as firm.

- In order to produce Base Case resource estimates, the PwC Consortium has mainly relied upon high levels discussions with operators who are actively exploring in Kenya as well as on publicly available estimates of unrisked resource potential.

- Kenya has good potential for oil and gas production however, in the Base Case, our estimates for potential oil and gas production in Kenya are still well below production levels in other more developed oil and gas producing nations. Nevertheless, as further exploration and drilling takes place additional resources may be discovered.

- Limited information is currently available from the MoEP and NOCK on oil and gas resource, but more information may be made available in 2015 once extended well testing in some areas is complete. GoK should also look to undertake a detailed geological study on oil and gas resource potential in the near future.

- MoEP and NOCK should reconsider the estimates provided in this Study once more information on oil and gas resource is available. This includes receiving detailed technical reports from oil companies operating within Kenya as per the requirements in the PSC, if and when available.

- We understand that there are still uncertainties relating to upstream investment and discussions are on-going between GoK and operators as to fiscal and other terms that might apply. The outcome of these discussions will greatly influence how much oil and gas is produced in Kenya and its timing.

# *Crude Oil Marketing*

# 5. Crude Oil Marketing

## 5.1. Introduction and Approach

### 5.1.1. Assumed Transit Supply

Kenya's neighbouring countries, Tanzania, Uganda and South Sudan have recently discovered significant amounts of oil and gas reserves. Unlike Tanzania, Somalia and Sudan, both Uganda and South Sudan are land locked and will require pipelines transiting another country (most likely Kenya) in order to export oil and gas internationally by sea. This Study only looks to provide a high level view of the transit potential through Kenya and does not attempt to determine production profile scenarios as undertaken for potential oil and gas resources in Kenya. Transit potential from Uganda is based on publicly reported estimates of expected annual production. Transit potential from South Sudan is based on historical production levels. Hence, transit potential should be considered as potential capacity requirements in a transit pipeline and not estimates of supply profiles.

#### 5.1.1.1. South Sudan

Sudan started producing crude oil in the 1990s and built two pipelines from the mid-south of the country to Port Sudan in the North on the Red Sea to export crude oil internationally. Proven reserves are currently estimated to be 5 billion barrels (billion bbl) of crude oil (approximately 50% recoverable) and 3 trillion cubic feet of natural gas. With the independence of South Sudan in July 2011, and with majority of the reserves originally being discovered in the mid-South; South Sudan's reserves of oil were estimated to be 3.5 billion bbl. to Sudan's share of 1.5 billion bbl.

Of the two pipelines, the Petrodar pipeline with capacity of 500,000 bbl/day currently transports the Dar Blend, a heavy sweet crude from South Sudan's Blocks 3 and 7 (41% CNPC, 40% PETRONAS, 6% Sinopec, 8% Nilepet, 5% Al-thani). The GNPOC pipeline with capacity of 450,000 bbl/day transports the Nile Blend, a medium, low-sulfur waxy crude oil from Blocks 2 and 4 in Sudan (40% CNPC, 30% PETRONAS, 25% ONGC, 5% Sudapet), and Blocks 1 and 5A in South Sudan (68% PETRONAS, 24% ONGC, 8% Nilepet). CNPC and PETRONAS are the major (>70%) shareholders in both pipelines.

Total oil production reached around 450,000 bbl/day in 2011 but dropped sharply in 2012 to 115,000 bbl/day after South Sudan shut in all its oil fields following political unrest with Sudan around the Heglig field. Following the agreement to demilitarise the buffer zone along their borders, South Sudan started production again in April 2013. However, since April 2013 there have been threats from Sudan to block South Sudan's use of the pipeline. South Sudan's current production is at around 160,000 bbl/day; much below the peaks of 250,000-300,000 bbl/day prior to unrest.

*Figure 5.1: Drilling information*


*Source: Drilling Info International*

Many believe production from South Sudan, which has been approximately double that of Sudan's, will drop quite quickly due to a lack of continued investment in exploration and production over the last few years. If political tensions and risk eases and investments are forthcoming, with larger proven reserves, production from South Sudan can quite easily recover up to 300,000 bbl/day.

In terms of natural gas supply potential, despite holding around 3 Tcf of associated gas between the two countries, gas is currently mostly flared or re-injected. It is unlikely that natural gas supply will be exported via Kenya as relatively small gas reserves are usually monetised domestically or used to enhance oil recovery (exports of gas as LNG would typically require much greater reserves).

### *5.1.1.2. Uganda*

The first commercial oil discovery in Uganda was near Lake Albert in 2006. Since then some 77 wells have been drilled and Uganda's proven reserves are estimated at 3.5 billion barrels of crude oil (approximately 50% recoverable) and 0.5 Tcf of natural gas. Total production is expected to be around 230,000 bbl/day beginning 2017/18. Production has been delayed owing to prolonged negotiations with upstream producers and in part identifying options to export the crude oil through Kenya. The Government is in the latter stages of planning the development of a new 60,000 bbl/day refinery in Uganda (30, 000 bbl/day initially up until 2024) which would rely on indigenous crude oil production. The contract for construction has been awarded to RT Global Resources and the refinery is planned to be commissioned in 2017/8 to coincide with major crude oil production start-up.

### *5.1.1.3. Transiting Kenya*

Being landlocked, there are few options for Uganda and South Sudan to export its crude oil. Having to share export pipelines with Sudan, South Sudan is looking to break away from the hold that Sudan has over it. It has publicly stated numerous times that it wants to diversify away from Sudan and export crude oil through Kenya. The extent of the diversification is unknown but may not be expected to be 100% given that key upstream players (CNPC and PETRONAS) have interests in both Sudan and South Sudan and are major shareholders of the two pipelines already built across Sudan. Furthermore, a major pipeline would still need to be built across

South Sudan to get to Northern Kenya. Other options include transiting Ethiopia and with exports from Djibouti, which is very unlikely for a number of reasons.

Uganda, which is geographically situated to the immediate West of Kenya, has really only Kenya as its option for transit and exports. Uganda could transit South Sudan and Sudan but would only be caught up in the political tensions between the two countries. While transit through Tanzania has also been discussed, this route is also unlikely given the given the longer distance and terrain to port.

The Governments of Uganda, Kenya and Rwanda recently commissioned a feasibility and preliminary engineering design study for a crude oil pipeline from Hoima near Lake Albert in Uganda, transiting through Kenya via Lokichar (in north-west Kenya) to the Port of Lamu. Having crossed South Sudan, Lokichar is convenient for crude oil pipeline from South Sudan to connect to. Hence, transit through Kenya for Uganda and South Sudanese crude oil seems a likely option.

In terms of transit potential, Uganda is expected to produce around 230,000 bbl/day, of which 30-60,000 bbl/day will be supplied into the domestic market, leaving around 170-200,000 bbl/day available for exports through Kenya. South Sudan's historical production has been as high at 250-300,000 bbl/day. Without a large scale refinery, all this supply is available for export. However, as mentioned above, not all production is expected to be export through Kenya. Some diversification away from Sudan can be expected to protect Government and oil producer incomes. We have therefore assumed only half of production (150,000 bbl/day) may be exported through Kenya in a second phase through a separate crude oil pipeline than for volumes from Uganda.

## 5.2. The Need for a Clear Pipeline Strategy

Discoveries in Lake Albert, Uganda and Turkana in Kenya's East Rift Valley have generated much optimism for Kenya oil exploration, and although still at an early stage, there is clear commercial potential. However, a critical factor to realising the potential economic value either of indigenous oil, or transit oil from neighbouring Uganda or Sudan, is the provision of an export pipeline system.

Indeed, without a clear, viable and executable plan in which upstream developers have confidence, 'final investment decisions' to develop identified resources to producing oil reserves will not happen. Without such a plan, the momentum of the exploration activities risks being blunted, or eventually being put on hold. This risk has been heightened by the recent collapse in global crude oil prices.

So the challenge is to formulate a strategy that is both clear, yet sufficiently flexible to cater for a range of potential outcomes, and prepare for its implementation.

### 5.2.1. Technical Factors Affecting the Pipeline:

**General Considerations**

Form a technical point of view the clear belief is that although challenging, it will be possible to identify a feasible route. In finalising the route the following factors will need to be considered:

- Coherent pathway – needs to maximize indigenous and transit opportunities
- Viable – shortest practical distance – heated line costs are very sensitive to distance
- Rapid construction: the geographical terrain, and machinery access impact ease of build
- Rights of Way: probability the most critical determinant. Every effort will be needed to coordinate discussions with stakeholders, and a single multi-lateral negotiation, to cover road, rail, pipe (for oil and or gas) as well as electric and other utility wayleaves
- Port suitability
- Security
- Consistency with country development plans

**a) Distances**

The pipeline project itself is technically challenging, requiring a heated pipeline to be laid over more than 860 km within Kenya from the Lokichar area to the Coast and cope with some 2,000 m3 of elevation. For transit oil the Lake Albert oilfield in Uganda would require a further 450 km to tie-in to the Lokichar area, and if South

Sudan were to identify oil south of Juba towards the border with Kenya, a connector pipeline of similar length would probably be required.

**b) Crude Quality**

The crude oil quality from both Uganda and Kenyan Rift valley are very similar and could be co-mingled, being low sulphur and waxy with pour point above 40 degrees C. As such the entire pipeline will need to be heated and lagged, and a minimum continuous flow will be required to maintain temperature and assure efficient pumpability. Although technically challenging, similar pipelines have been laid in Chad and elsewhere, and the upstream companies that have carried out extensive feasibility studies are confident that these pumping and heating challenges can be overcome.

The crude oil quality from existing South Sudan production differs from the Ugandan/Kenyan grade, being less waxy but more acidic (high TAN). As such any Sudanese crude may need to be segregated to protect commercial values, though whether new discoveries South of Juba would be of similar quality remain to be seen.

**c) Capacity and Timing – A scale-able approach is needed**

In determining the pipeline capacities, there is clearly a wide range due to:

- The early stage of Kenyan Oil field development (and the need for GoK to reach a durable agreement with developers for financial and fiscal arrangements that support continued investment).
- The lack of a defined commitment between Uganda and Kenya for transit of Lake Albert crude oil.
- The uncertainty surrounding the rate of development, location and quality of new South Sudanese crude oil.

However, the situation is simplified if we consider those projects realistically capable of being developed now, and therefore ready to commit to Take or Pay agreements for use of capacity, and those which will take more time.

- We understand that both the Turkana Oilfield and Lake Albert Oilfields projects are potentially ready to be developed. They are compatible crudes, and could be brought onstream in the 2018-20 period.
- Despite encouraging signs, other oil exploration projects in Kenya will take more time to become investment ready. These projects may potentially require 3 – 7 years.
- It is unlikely that Sudan could consider a firm commitment, until it is clear about its other medium term options with Sudan and Ethiopia – this seems likely to require several more years yet. This is particularly so for potential oil resource close to the Kenyan border, which although more favourably located, is the least developed.

**What is really needed is to define an approach that is proportionate to current firm requirements, yet scale-able to accommodate the other potential options as they mature.**

For this reason, we would envisage a first phase pipeline system that meets the needs of the projects ready to commit to its use, but provides stakeholders with commercial, engineering and operating frameworks that can be readily extended when opportunities arise.

The precise timing will need to be coordinated between the interested parties, however, we would foresee the following phases:

**Phase 1: 2018-2020**

- From Turkana fields in Kenya – a requirement of approximately 100 kb/d.
- From Lake Albert in Uganda– a requirement to transit 170-230 kb/d.

The overall pipeline capacity would be in the 270-330 kb/d range, and with a normal minimum operating throughput of approximately 100 kb/d. Our understanding is that this is consistent with the technical pipeline flow and crude oil heating requirements, and that these projects could be potentially developed in a coordinated manner.

To achieve this goal will require prompt action in a number of key areas, notably:

- Clarification of the preferred routing. Support to obtain rights of way.

- An intergovernmental agreement setting out the vision for the first phase system, commercial use principles, approach to design, construction, and operation of the system.
- A separate paper considering funding options for initial construction, medium/longer term options for either expansion or transfer of ownership.

**Phase 2: 2021 onwards**

Further exploration in Uganda and Kenya over the next five years or so, the evolution of the South Sudan situation and the general economic environment will inevitably affect requests for additional pipeline capacity.

The likely range of requirement could be as little as 50 % to as much as 200% of the Phase 1 requirement.

Three basic options exist that meet such future needs

- De-bottleneck the Phase 1 pipeline. This may make sense if additional capacity is at the lower end of the expected range and the crude oil quality is compatible.

- Run a second Phase 2 pipeline adjacent to the Phase 1 pipeline. This would be would be the preferred solution if considering very different crude oil quality or if the additional capacity required is either similar to or greater than Phase 1. Sharing rights of way and pre-preparation of civil engineering work for a second line during Phase 1 could significantly reduce Phase 2 project timeline.

- Consider a completely separate pipeline route. Depending on the specific oilfield under consideration, this could appear a shorter, lower cost option. However, the time required to obtain new rights of way and loss of operational synergies may outweigh potential savings.

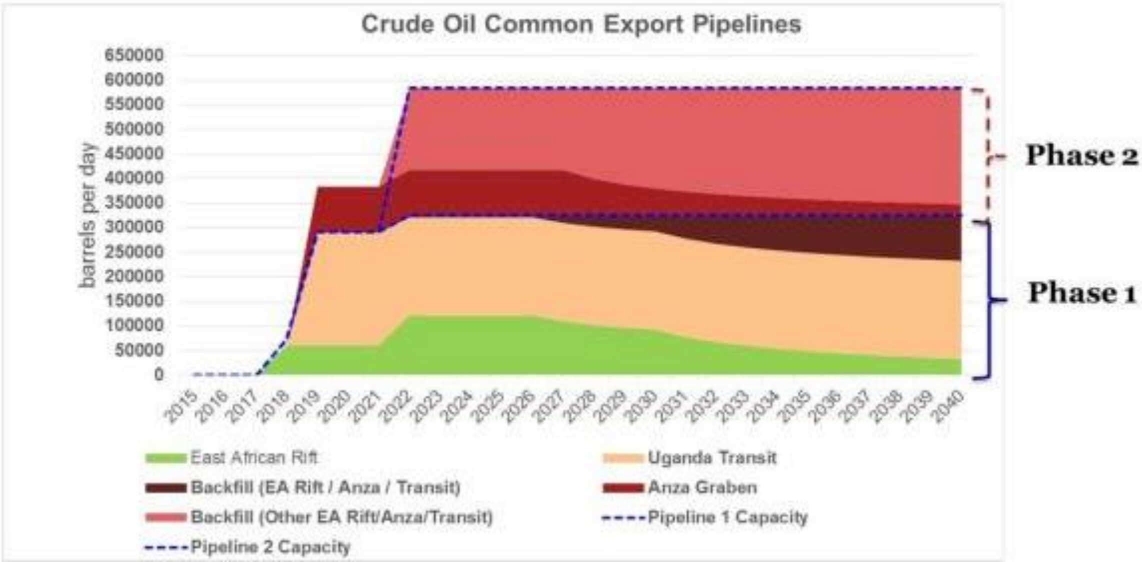
We would recommend that the Base Case plan would be to build Phase 1 pipeline plus the Phase2 civil engineering work, so that Phase 2 expansion is seen as a relatively low risk project, with predictable costs and a rapid implementation timeline.

For Master Planning purposes, we would further recommend that the Base Case should assume a Phase 2 expansion nominally 5 years after Phase 1 completion, though it is recognised that a flexible approach will need to be adopted as the expansion will ultimately be driven by a critical mass of developable oil.

It is envisaged that once either Phase1 or Phase 2 capacity has been made available, producers will look to maximise throughput on the pipeline(s). Eventually, as spare capacity becomes available due to declining output in these principal oil fields, it should be taken up with additional production from smaller reserves. An illustration of how this could work is set out in the figure below.

*Figure 5.2: Illustrative initial use and backfilling of crude oil pipeline capacity*

***Economic viability of Phase 1 in the short term is dependent on the combined Kenyan and Ugandan volumes.***




*Source: PwC Consortium Analysis*

## *5.2.2. Commercial Factors Affecting Development*

**Impact of Crude Oil Prices**

Very recently there has been a substantial fall in oil prices, and these falls inevitably impact project viability. Ultimately prices reflect the fundamentals of Supply and Demand, with higher than anticipated U.S. shale oil production and weaker than forecast Asian (particularly Chinese) demand growth. However, these falls were met by rapid announcements of cuts in upstream investment for more marginal oilfields, and in over 2 to 3 years we would expect the prices to return to the US$ 80- US$ 100 per barrel range.

**Energy Policy and Competitiveness**

What is important is that MoEP maintains a vigilant approach to the overall attractiveness of upstream investments in Kenya, in relation to competitiveness across Africa and the wider Asian region. Investors need to understand that the Government stands ready to support the upstream industry through more difficult periods, as well as raise taxes on 'windfall' gains.

**Impact of Achieving a Relatively Stable and Attractive Investment Climate**

Provided investors have confidence in the responsiveness of Government to changing situations, a steady stream of exploration projects should be able to be developed, and therefore once these pipelines have been constructed, the expectation in the period to 2040 is that they would remain full as additional smaller fields can be connected. This should lead to a reasonably predictable oil revenue stream for transit oil even though Government revenues for equity will still be susceptible to changes in world oil prices.

## *5.2.3. Routing Options for the Pipeline*

**Regional Context for Kenya**

The routing options for the Kenya crude oil export pipeline needs to take into account not only the potential areas of indigenous production in the Rift Valley and Anza Basins, but also the interests of neighbouring Uganda and South Sudan who have a potential requirement to transit their crude oil through Kenya to the Indian Ocean. The picture is further complicated by existing and potential export pipeline routes through Sudan, Ethiopia/Djibouti and Tanzania, all of which provide potential alternatives, as are shown in the map below.

For Uganda, both the routes identified through Kenya are shorter and therefore potentially cheaper than the alternative provided by Tanzania. There is extensive history of cross-border oil trade between Kenya and Uganda, and it would appear reasonable that if a well-constructed proposal were to be developed, the chances of reaching a durable agreement look favourable. (This is further supported by the recent joint Kenyan/Ugandan/Rwandan appointment of consultants to consider the feasibility of an export pipeline from Hoima to Lamu).

For South Sudan, the position appears more complicated. The stability of relations with their northern neighbor Sudan would inevitably be improved by maintaining a trade agreement to transit oil via Sudan's existing pipelines to Port Sudan, and this agreement is due for renewal in 2016. Although alternatives need to be considered, Ethiopia, who has established considerable military strength, may be the preferred partner if the route to Djbouti is shown to be technically feasible and commercially viable. These issues are far from certain, however, and are unlikely to be known for at least a year. So for Kenya, reaching agreement with South Sudan remains a possibility, though considerable uncertainty remains as to whether or when it might happen.

*Figure 5.3: Map of current and potential regional routes*


*Source Economist May 2013*

**Preferred Routing Within Kenya**

**A: <u>The Southerly Route</u>**

Within Kenya this route runs from the Kenyan border in the Eldoret area and broadly follows the oil product pipe track back towards Nairobi and then on to Mombasa, where a new crude oil export terminal would need to be constructed. The driver for consideration of this route was to transit Ugandan oil discoveries in the Lake Albert area, and a corresponding Ugandan section of the line would also be required from Hoima to the border area towards Eldoret. This is the shortest and most direct routing for Lake Albert crude oil exports. However:

- there are no existing rights of way through Kenya to facilitate development, as the oil product pipeline relies upon 'easements' and these couldn't be expanded to cater for a larger crude oil pipeline. Obtaining these 'rights of way' through the relatively developed areas around Eldoret, Nakuru, Nairobi and Mombasa is anticipated to be a time consuming and complex process.

- due to its routing through developed areas in and around Nairobi and needs to navigate the congested areas around Mombasa, there are many crossings to be put in place which will slow the construction process.

- following discoveries of Kenyan crude oil from the Rift Valley and Anza basin, for this line to be beneficial to the Kenyan upstream oil sector, a long connector pipeline would be required from the Lokichar area to Eldoret.

**B: The Northerly Route**

- The Northerly route runs from Lokichar to the Port of Lamu along the LAPSSET Corridor. Although some 10% longer for Ugandan oil, this route would be a shorter pathway for Turkana crude oil and other discoveries along the Rift Valley and Anza region. This Northerly routing supports the Kenyan vision to create a major new infrastructure corridor. Furthermore, construction may be faster since the area is largely undeveloped.

- However, the LAPSSET corridor itself will still pass through the smaller developed areas along the route to the border north of Lokichar.

- The LAPSSET runs along the arid areas approaching the Somali border, since pipeline security needs to be assured, the precise routing needs to favour effective policing of the route.

- Most importantly, the LAPSSET routing meets the Indian Ocean at the port of Lamu. This is a shallow fishing port, with much of the local business based on tourism, and not well suited to the loading of large oil tankers.

**C: Northerly Route (modified)**

- As part of the development process for the Turkana oil fields, the developers have expended a substantial effort to review the Northerly route, and considered how it could be made a more robust proposal for oil exports, be lower impact in its construction and operation, and more compatible with the lives and activities of the local area.

- The key changes would be to

  - Build a separate oil export terminal 40 or 50 km to the South of Lamu, and load oil tankers via an offshore mooring, located several kilometres out to sea. This will provide deep water required by the vessels to keep the oil operations well away from the shore and avoid impacting tourism or other local activities.

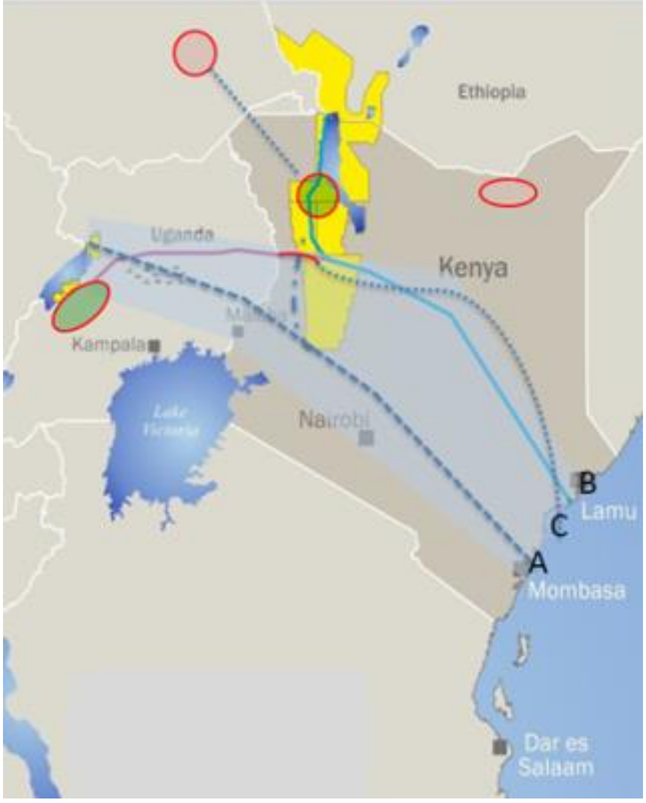
  - Although following the broad direction of the LAPSSET corridor, use a detailed routing that minimises crossing points in developed areas along the route. This should further ease rights of way issues and speed construction.

Overall, given the early stage of development of upstream oil within Kenya, the future possibilities of other transit crude oil from South Sudan, the need for scale-ability for future increases to capacity, the preferred routing from a Master Planning perspective would be option C – the modified Northerly route.

Consideration of the unique opportunity to support the LAPSSET corridor, with its potential to improve the lives of many Kenyan people and the realization that the more congested Southerly route is best reserved for expanding the oil product pipeline, to ensure that the principal areas of existing population will be well served into the future supports this approach.

The Ugandan interests remain a very important consideration in this decision. Despite their initial preference for the Southerly route, given the potential for faster construction via the modified LAPSSET route, we believe a persuasive case can be made for option C.

*Figure 5.4: Crude oil export pipeline – routing options*




*Source: PwC Consortium Analysis*

**Governmental Role in Clarifying the Pipeline Vision and Key Principles**

In order to progress pipeline development, the investors in the pipeline company will require not only contractual commitments to be put in place with upstream developers, but a clear governance framework from well to export terminal, so that responsibilities for project delivery for each section of the pipeline and management of risks/issues are clearly defined. Where the oil flows across national borders, this will require a bi-lateral intergovernmental agreement be put in place.

Therefore, assuming the preferred first phase of crude oil pipeline development is primarily to export Lake Albert and Turkana crude oil, as a the first step GoK should engage in a dialogue with the Ugandan Government with a view to clarifying the proposed scope, timing, routing and capacity of this first phase of the pipeline, and jointly appoint a lead contractor to carry out a full feasibility and cost estimation for the pipeline system.

It is assumed that this system will comprise:

- A central crude stabilisation unit, and interim storage facility in the Lokichar area.
- A heated common export pipeline, with the capacity of 270 to 330 kb/d which runs from Lokichar to the finally agreement export terminal location.
- Ugandan and Kenyan connector line sections. Firstly- between Hoima and Lake Albert, and secondly, from the Turkana oil field to Lokichar.
- An export and storage terminal.
- A sea line and single point mooring system.

**Special Purpose Vehicle Structuring for the Crude Oil Pipeline System**

Given the highly technical nature of the project, it is strongly suggested that the upstream stakeholders are allowed the opportunity to contribute to technical design, approval and implementation of the project.

It is envisaged that the common sections of the system from the receiving station at Lokichar to the Export terminal line would be financed and operated as the 'Kenya Export Pipeline System' and using a structure of throughput agreements and tariffs.

In addition, the connector lines from individual oilfields to the Lokichar gathering system would be constructed as separate but complementary projects, with additional separate tariffs that would reflect the costs of these connector lines. Due consideration should be given at the design stage to potential for capacity upgrading, consistent with the Phase 2 base case, though due to the existing uncertainty as to which oilfields might participate in the expansion, it is recommended that incremental costs for connector line during phase 1 is minimised.

Where the pipelines cross-national boundaries, it is envisaged that separately incorporated special purpose vehicles/companies (e.g. Uganda – for Phase 1) would be established and responsible to their national Government for delivery of their tranche of the pipeline.

**Funding and Ownership of the Pipeline System**

A variety of funding mechanisms could be considered for the system. A detailed discussion of the potential funding options available is discussed under 8.7.

It is also recommended that the upstream industry participates in the organisational design, appointment and operation of the system for the first 5-7 years of the project, during which time all development issues are assumed to have been resolved, and a period of several years of steady operational performance will be demonstrated.

Subject to prevailing economic conditions at that time, GoK and possibly other original equity stakeholders, may wish to consider a dilution of their shareholdings to allow for wider public ownership, possibly via an IPO.

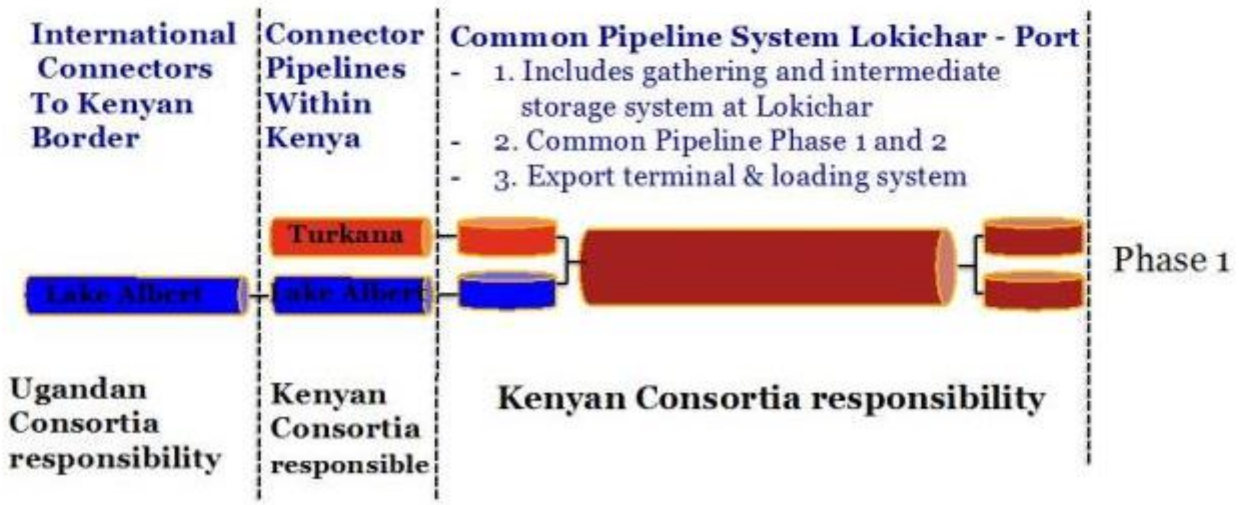
**Engineering the Pipeline in Packages, Country Responsibilities and Operation**

The engineering design should ensure that overall system could be expanded to accommodate a second phase pipeline of nominally similar capacity, with planning for additional storage, lines and loading buoys, so that all planning approvals/consents and any critical civil works could be carried out as part of the first phase activity.

The figure below illustrates the way in which the project could be subdivided, with each Consortia in each country responsible for building their own section, and the common export pipeline system being packaged as a separate company, to individual connector lines, that would be engineered in conformity with the overall system requirements, but potential funded separately with dedicated users.

It is envisaged that once commissioned, a single overall Management team would assume responsibility for scheduling of all movements across the system.

*Figure 5.5: Crude oil export pipeline- Packaging the project*



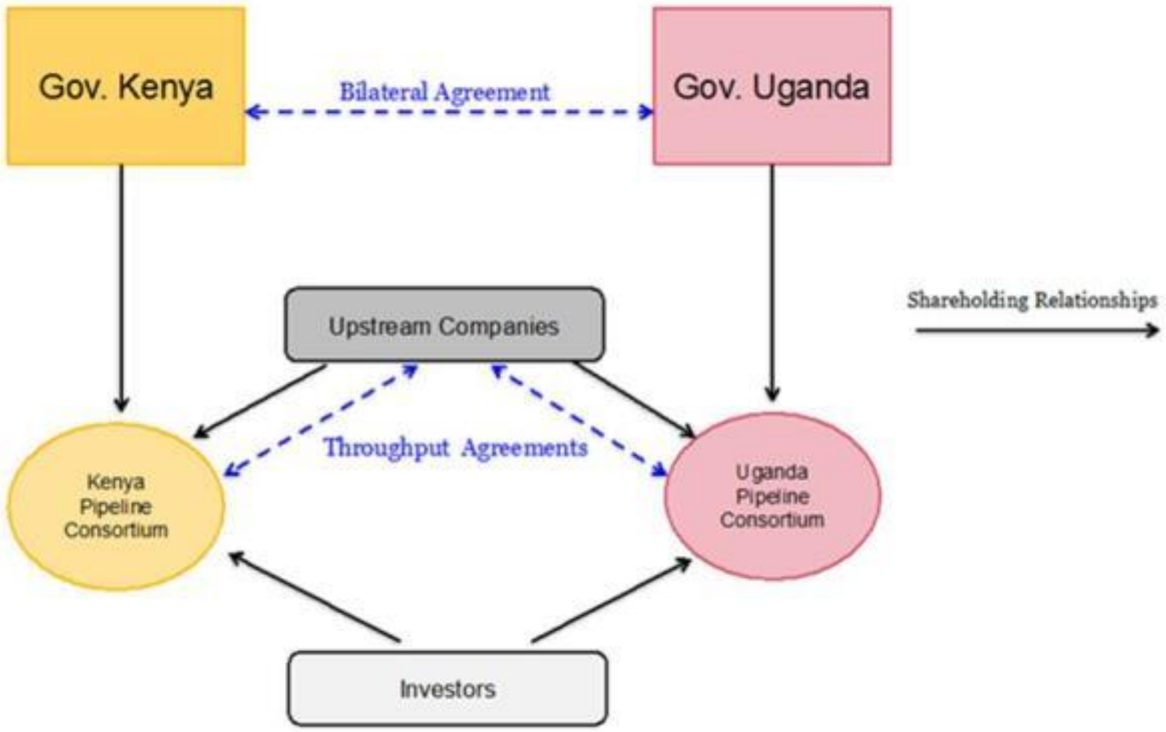

*Source: PwC Consortium Analysis*

### Bi-lateral intergovernmental agreements

Once the Engineering Design Package (often referred to as the FEED – Front End Engineering Design) has been completed, the Governments should meet again with a view to reaching a binding Construction Agreement on the detailed overall engineering project, its timeline, and the division of scope and responsibilities between a Ugandan consortium and Kenyan consortium that collectively will comprise the overall system.

At this stage it is further envisaged that the Governments and upstream companies who require capacity in the Phase 1 pipeline would enter into individual Take or Pay Agreements, to commit to a defined annual fee structure for the right to use an agreed capacity on both the common on connector sections of the line. These individual agreements should fit within the framework of an overall Commercial Agreement that includes the rationale for initial tariffs and subsequent revisions, allocation and use of capacity between throughputters, timing and duration, mechanisms to cope with requests for change in the future.

*Figure 5.6: Setting up the Governmental and throughputting agreements*




*Source: PwC Consortium Analysis*

### Capital Costs and Investors

Current estimates of capital expenditure for the heated crude oil pipeline relate to Phase 1 of the common crude oil pipeline from Hoima via Lokichar to Lamu and range from US$ 3.5b to US$ 5b excluding the tie in from the Turkana fields to the Lokichar gathering station.

A preliminary engineering study for the Hoima – Lokichar-Lamu line will provide further detail on costs and is due to report by May 2015.

This should provide a basis on which to solicit potential interest from the investment community although a full front end engineering study would normally be required to provide sufficient detail and the precision required for actual investment decisions.

## 5.2.4. Conclusions

A number of key decisions and actions need to be made by the Government of Kenya in order to achieve the successful development of a crude export pipeline at the earliest opportunity:

- Reach a Binding Intergovernmental Agreement With Uganda for the Joint Construction Of the Crude Oil Export Pipeline ("Construction Agreement"). This should be a scale-able solution that provides for a future Phase 2 expansion.
- Commercial agreement for users of Phase 1 of the pipeline system, and the joint appointment of a lead contractor with overall design and project responsibility.
- Approval of rights of way within Kenya along the chosen route within a defined timeline.
- Setting-up of both Ugandan and Kenya consortia to realize the required engineering packages in each country.

# *Downstream Oil Sector*

# 6. Downstream Oil Sector

## 6.1. Outlook for Oil Demand- Kenya and Region

### 6.1.1. Kenya Oil Demand

In developing a Master Plan for the oil sector a key component is an understanding of the forecast growth in oil demand over the period in order to plan and develop the required supply infrastructure to meet the increased demand efficiently and effectively. The projections of the volumes of liquid fuels that will be consumed to the year 2040 for Kenya are built on scenarios of world economic growth, the global oil market and the domestic economy. World economic growth is expected to move ahead in three tiers. The initial tier being Europe, OECD (Organisation for Economic Co-Operation and Development) countries, and Asia which will grow at the slowest pace, followed by North America as tier 2 growing at a higher level, and finally the non-OECD or Emerging and Developing Countries growing at the fastest pace of around 4.4% per annum to the year 2040. These uneven growth rates have seen the bulk of the demand for crude oil and refined petroleum products move from the developed world to the developing world, a trend that will continue and grow in magnitude.

Oil has been a dominant factor in primary energy consumption over the past century but has fallen from a peak of 48% in 1973 to 33% in 2011. Although natural gas is expected to become more widely used in the future, oil is forecast to remain the dominant transport fuel, as world trade continues to expand. World economic growth momentum is shifting to the emerging and developing countries and for the first time in 2013 this group of countries consumed more of the world's oil than the developed or advanced economies. The gap in global economic growth rates is expected to continue driven by population growth, urbanization, the movement away from subsistence agriculture, the development of skills and the harnessing of technology.

Kenya is a large country of 580,367 square kilometres and is roughly the size of France. However its population of approximately 45 million[19] in 2014 is mostly rural with an urban population of 24.4% of the total population in 2012. In addition, the incidence of poverty is high. According to the Kenya Population and Housing Census of 2009, 45.2% or almost half of the population was living below the poverty line. This is determined based on the expenditure needed to purchase a basket of food that meets minimum nutritional requirements in addition to the costs of basic non-food needs (Kenya National Bureau of Statistics 2014:291).

The structure of the economy currently comprises a relatively large primary sector at 26.4% of GDP in 2013, made up of the growing of crops and horticulture as its largest segment (19.4%). This is important as this is where the key export commodities of tea, coffee and cut flowers amongst others originate. Other primary sector components are set to boost the economy in the forecast period, particularly oil. The secondary sector is relatively undeveloped at 14.7% in 2013. Indeed in the forecast period to 2040, this secondary sector is unlikely to become a bigger percentage of GDP, as the tertiary sector is forecast to grow from its current level of 49.0% in 2013, as services grow and Kenya retains its role as the logistics and financial hub of East Africa. Proposals such as a monetary union in East Africa are a possibility with Kenya playing a leading role. Kenya is set to remain the logistics hub serving Rwanda, Uganda and South Sudan through Mombasa, and increasingly into Ethiopia through the port of Lamu; the LAPSSET Corridor project also looks likely to be developed in the Master Planning period. This will require enormous investment locally and from abroad and security issues need to be addressed. The construction of a standard gauge railway line from Mombasa to Nairobi, and in phase 2 to Lake Victoria before connecting with Uganda to Kampala, commenced in May 2014 which will both relieve pressure on the road network and enhance the movement of bulk goods from the coast to Nairobi.

Six sectors have been identified on the basis of their potential to contribute to the 10% GDP growth as part of Vision 2030. These are listed below with comments as to their capability to realise the annual 10% GDP target.

- Tourism – where socio/political unrest and terrorism are severe inhibitors to growth.
- Agriculture – where there is reliance on too few basic products with volatile prices.
- Wholesale and Retail Trade – potentially a large employer and conduit to other countries inland.
- Manufacturing – need to develop beyond small-scale consumer goods (such as plastic, furniture, batteries, textiles, clothing, soap, cigarettes, flour), agricultural products, horticulture, aluminium,

[19] CIA World Fact Book, December 2014

steel, lead, cement and commercial ship repair.

- Information and Communications Technology ("ICT") and Business Process Outsourcing ("BPO") – widen access to internet and communication.
- Financial Services – increase availability of credit, particularly for small, medium and micro enterprises.

Vision 2030 is seen to be progressing towards its goals and one of the key ingredients is going to be the lowering of the cost of power and the expansion of connectivity and its availability. Export Processing Zones (EPZs) are important to lead the progress to 10% per annum GDP growth as they take advantage of their favourable environment including tax incentives to attract new investment. However, the extent of Kenya's oil discoveries and how this resource will be managed is important to the attainment of the targeted growth rate.

The economy is seen to be diversified and not reliant on any particular sector. Agriculture, tourism and the financial sector all play major roles. As such, when the crude oil potentially comes onstream it should seek to complement them.

Kenya is well positioned to take advantage of the growth of its neighbours as well as the momentum of its own economy.

The Base Economic Growth Case is predicated on:

- the development of the LAPSSET Corridor,
- the establishment of recoverable resources of oil of 1 billion barrels; and
- a long term oil price in excess of US$ 100 a barrel in 2014 money.

This is laid out in the table below. Government consumption expenditure is forecast to grow at 6.2% per annum in real terms as the State progresses its socio-economic agenda described above in terms of Vision 2030 and the successive medium term plans. Exports increase at the fastest rate of all the variables in this scenario. As the crude oil fields are exploited the economy develops and moves towards middle income status. Overall GDP growth of 6.6% per annum is achieved. Investment reaches 25% of GDP in 2040 after growing by 8.5% per annum for the period 2009 to 2013. GDP per capita in US Dollar terms doubles by 2040, but is not enough to take the nation to middle income status as forecast in Vision 2030.

*Table 6.1: Base case - LAPSSET and recoverable oil resources of 1 -3 mill barrels*

| **Gross Domestic Product by type of expenditure at 2001 prices KES millions - Base Case: LAPSSET and moderate oil** | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **2013** | **2020** | **2025** | **2030** | **2035** | **2040** | **% of GDP** | **AAI 2013-2040** |
| **Final Consumption Expenditure** | 1,590,348 | 2,349,790 | 3,219,416 | 4,393,770 | 5,996,950 | 8,185,702 | 86.49% | 6.26% |
| ***% Change*** | *5.25%* | *6.08%* | *6.50%* | *6.42%* | *6.42%* | *6.42%* | | |
| Government **Consumption Expenditure** | 255,801 | 391,930 | 536,978 | 718,598 | 961,646 | 1,286,899 | 13.60% | 6.17% |
| ***% Change*** | 9.55% | 6.50% | 6.50% | 6.00% | 6.00% | 6.00% | | |
| **Household Consumption Expenditure** | 1,334,547 | 1,957,860 | 2,682,438 | 3,675,172 | 5,035,304 | 6,898,803 | 72.89% | 6.27% |
| ***% Change*** | 4.46% | 6.00% | 6.50% | 6.50% | 6.50% | 6.50% | | |
| **Gross Capital Formation** | 460,392 | 971,188 | 1,239,509 | 1,581,963 | 1,943,206 | 2,364,208 | 24.98% | 6.25% |
| ***% Change*** | 2.30% | 7.00% | 5.00% | 5.00% | 4.00% | 4.00% | | |
| **Gross Domestic Expenditure** | 2,035,529 | 3,320,978 | 4,458,925 | 5,975,733 | 7,940,157 | 10,549,910 | 111.47% | 6.28% |
| ***% Change*** | 4.08% | 6.35% | 6.08% | 6.04% | 5.82% | 5.87% | | |
| **Exports of Goods and Services** | 475,024 | 1,011,994 | 1,629,826 | 2,181,075 | 2,918,770 | 3,905,972 | 41.27% | 8.12% |
| ***% Change*** | 2.78% | 10.00% | 10.00% | 6.00% | 6.00% | 6.00% | | |
| **Imports of Goods and Services** | 798,643 | 1,672,326 | 2,400,840 | 3,064,148 | 3,910,716 | 4,991,175 | 52.73% | 7.02% |
| ***% Change*** | 2.78% | 5.00% | 7.50% | 5.00% | 5.00% | 5.00% | | |
| **Total GDP at Constant Prices** | 1,686,149 | 2,660,645 | 3,687,911 | 5,092,659 | 6,948,211 | 9,464,708 | 100.00% | 6.60% |
| ***% Change*** | 4.69% | 8.60% | 6.84% | 6.66% | 6.36% | 6.39% | | |
| **Kenya Inflation** | 6% | 4% | 3% | 3% | 3% | 3% | | 3.4% |
| **US CPI - Increasing by AEO 2012** | 2.1% | 2.0% | 2.0% | 2.3% | 2.3% | 2.3% | | 2.2% |
| **Population millions** | 44 | 53 | 61 | 70 | 81 | 93 | | 2.76% |
| **GDP per capita US$** | 4,956 | 6,504 | 7,855 | 9,450 | 11,233 | 13,331 | | 3.73% |
| **Oil Price $/barrel Real 2011** | 110 | 106 | 117 | 130 | 145 | 163 | | 1.46% |
| **Oil Price % change** | -0.58% | -0.58% | 2.14% | 2.14% | 2.19% | 2.27% | | |
| | | | | | | | | |
| | | | | | | | | |
| ***Source: Kenya National Bureau of Statistics, Second Medium Term Plan & G McGregor*** | | | | | | | | |
| ***Note: AAI% = Average Annual Increase*** | | | | | | | | |

The objective is to forecast the domestic demand for liquid fuels for Kenya for the period 2014 to 2040. Demand is a function of several components but chiefly of real price, real income and other factors such as urbanisation, substitute products and complementary products, where applicable.

Liquid fuels demand is driven in the broader sense by the following variables:

- The International economy and the effects this has on the growth of the economy in question.
- The world oil markets and consequently the price of crude oil and the international prices of refined petroleum products.
- Domestic factors that influence the economic activity of the local economy.

These factors are combined as exogenous variables to produce the Base Case petroleum volume forecast (using regression analysis and other methodologies as described in more detail in Appendix F).

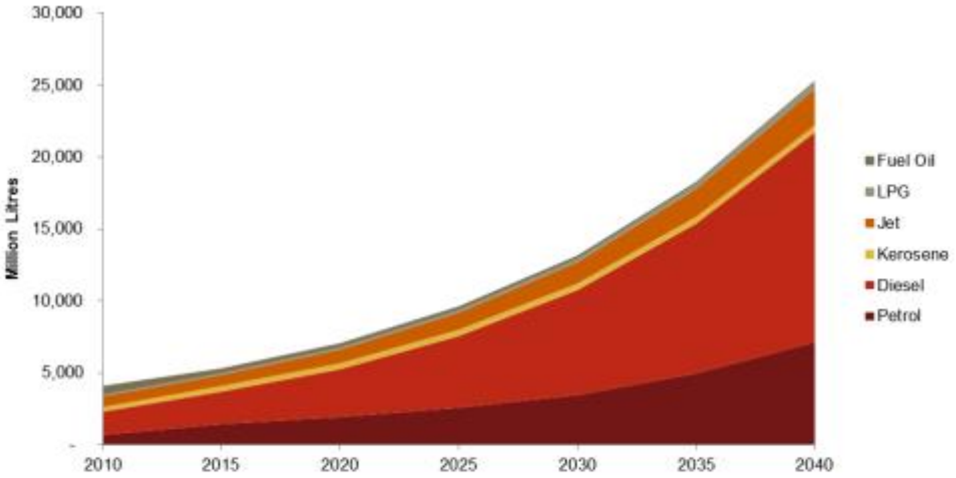
As economic growth is predicted to be higher in the plan period compared to 2000 to 2013 petroleum product volume growth rates are higher than that achieved over the past decade. One of the primary reasons for this higher growth is the essence of this Study, namely the discovery and commercialisation of oil and natural gas.

Petrol volumes are relatively sensitive to price compared to diesel but as the real petrol price is expected to be flat in the forecast period, petrol volumes will grow in line with buoyant economic growth between 2014 to 2040 in the Base Case. Similarly diesel and jet volumes will feed off expected higher GDP growth in the forecast period and grow faster during the forecast period to 2040 than from 2000 to 2013, whereas fuel oil is forecast to continue its decline.

LPG demand has been based on a 4 to 5.6% growth in the Base Case based on current supply constraints. In the event these are removed and supply infrastructure is built, a recent 2013 LPG study indicated that demand could double the forecast to over 10% growth p.a. The report suggests current published LPG statistics could be understated as the full imports ex Zambia and Tanzania might not be included in the current statistics. The infrastructure required to develop the LPG market is discussed in more detail in section 6.2.9.

The average annual increases of the petroleum product volumes for the past decade and for the 2014 to 2040 are shown in the figure below:

*Figure 6.1: Base-case projections*




*Source: PwC Consortium Analysis*

*Table 6.2: Petroleum product growth 2000 to 2013 versus 2014 to 2040 Base case*

| **Kenya domestic petroleum product demand 2000 2040 base case** | | | | | | | |
|---|---|---|---|---|---|---|---|
| | **Petrol** | **Diesel** | **Kerosene** | **Jet** | **LPG** | **Fuel Oil** | **Total** |
| ***AAI 2000-2013** | 6.5% | 6.5% | 0.1% | 3.8% | 4.6% | -2.8% | *4.1%* |
| ***AAI 2014-2040** | 6.6% | 7.7% | 0.8% | 4.9% | 5.4% | -3.8% | 6.4% |

* AAI – Annual Average Increase

*Source: PwC Consortium Analysis*

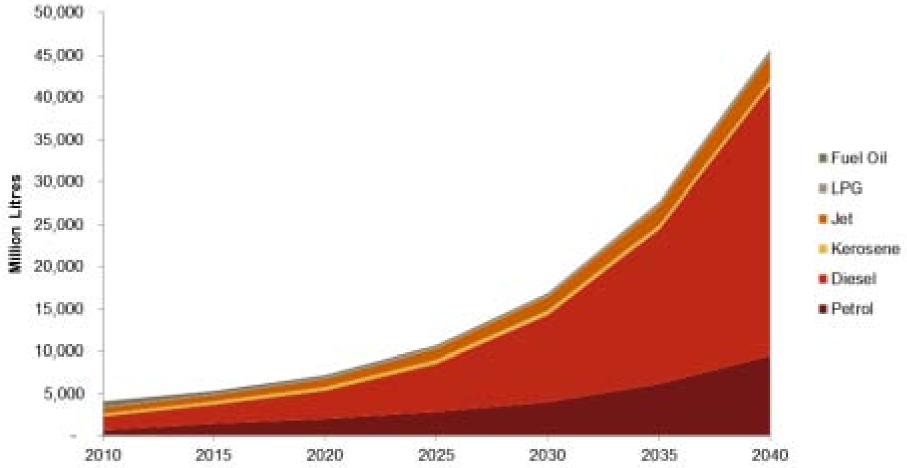
The net effect is that Kenya petroleum product demand is forecast to double by 2030 and double again by 2040. This underlines the need to increase the storage and distribution infrastructure to ensure there is an efficient supply of petroleum product to the consumers across Kenya.

## 6.1.2. Kenya Petroleum Demand Sensitivities

Oil demand sensitivities have been run on a high and low case as set out below:

The High Case shows Kenya achieving Vision 2030, with abundant developed oil and gas reserves and needing liquid fuels growth of 8% per annum to meet this economic growth. This results in forecast fuel demand growing threefold from 2030 to 2040.

*Figure 6.2: High-case projections*




*Source: PwC Consortium Analysis*

*Table 6.3: Product growth 2000 to 2013 versus 2014 to 2040 High case*

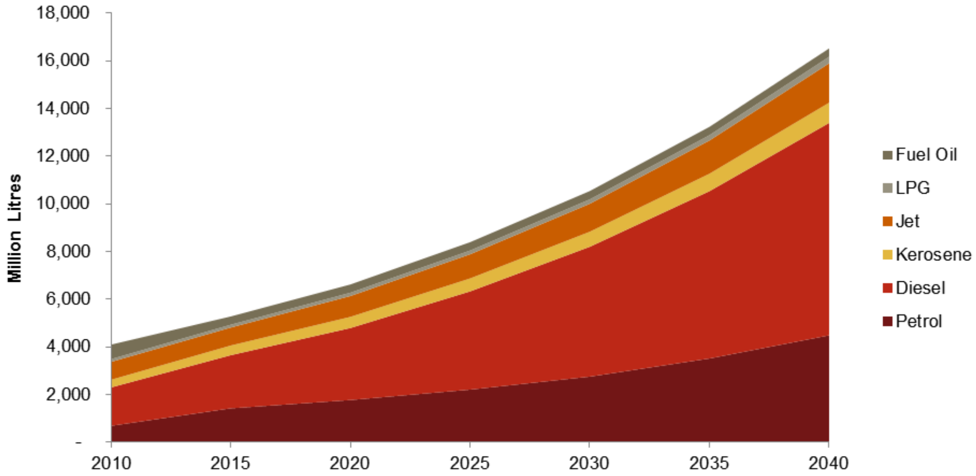
| Kenya domestic petroleum product demand 2000 to 2040 high case | | | | | | | |
|---|---|---|---|---|---|---|---|
| | **Petrol** | **Diesel** | **Kerosene** | **Jet** | **LPG** | **Fuel Oil** | **Total** |
| ***AAI 2000-2013** | 6.5% | 6.5% | 0.1% | 3.8% | 4.6% | -2.8% | *4.1%* |
| ***AAI 2014-2040** | 7.8% | 11.0% | 1.2% | 5.6% | 6.9% | -7.0% | 8.8% |

* AAI – Annual Average Increase

*Source: PwC Consortium Analysis*

The Low Case shows the economy continuing as is with no real impetus from limited new crude oil discoveries and limited investment. Petroleum product growth is forecast to be lower at 4.7% than during the period from 2000 to 2013.

*Figure 6.3: Low-case projections*




*Source: PwC Consortium Analysis*

*Table 6.4: Petroleum product growth 2000 to 2013 versus 2014 to 2040 Low case*

| **Kenya domestic petroleum product demand 2000 to 2040 low case** | | | | | | | |
|---|---|---|---|---|---|---|---|
| | **Petrol** | **Diesel** | **Kerosene** | **Jet** | **LPG** | **Fuel Oil** | **Total** |
| ***AAI 2000-2013** | 6.5% | 6.5% | 0.1% | 3.8% | 4.6% | -2.8% | *4.1%* |
| ***AAI 2014-2040** | 4.7% | 5.7% | 3.0% | 3.2% | 3.4% | 0.0% | 4.7% |

* AAI – Annual Average Increase

*Source: PwC Consortium Analysis*

The sensitivities highlight that even in the low-case projections, product demand is forecast to increase at least threefold over the Master Planning period.

A clear vision and regular update of demand forecasts are needed to ensure that the supply chain infrastructure and operational capacities are in place to meet consumer demand.

**Note: Please see Appendix F for a more in depth review of oil demand.**

## *6.1.3. Kenya and Regional Pipeline Fed Oil Demand*

An understanding of the split of the geographic demand within Kenya and the region is necessary in order to be able to plan the required supply and pipeline infrastructure required to meet the forecast demand in the requisite locations.

Petroleum demand comprises six major products: premium motor spirit or gasoline, jet fuel, gasoil, DPK or illuminating paraffin, LPG and fuel oil. LPG and fuel oil are normally transported by rail or road whereas the lowest cost bulk transport medium for the balance is by pipeline.

Kenya is also the major transit route inland for Uganda, Rwanda Burundi, and Eastern DRC, and also supplies product to Southern Sudan and a limited volume to North Eastern Tanzania.

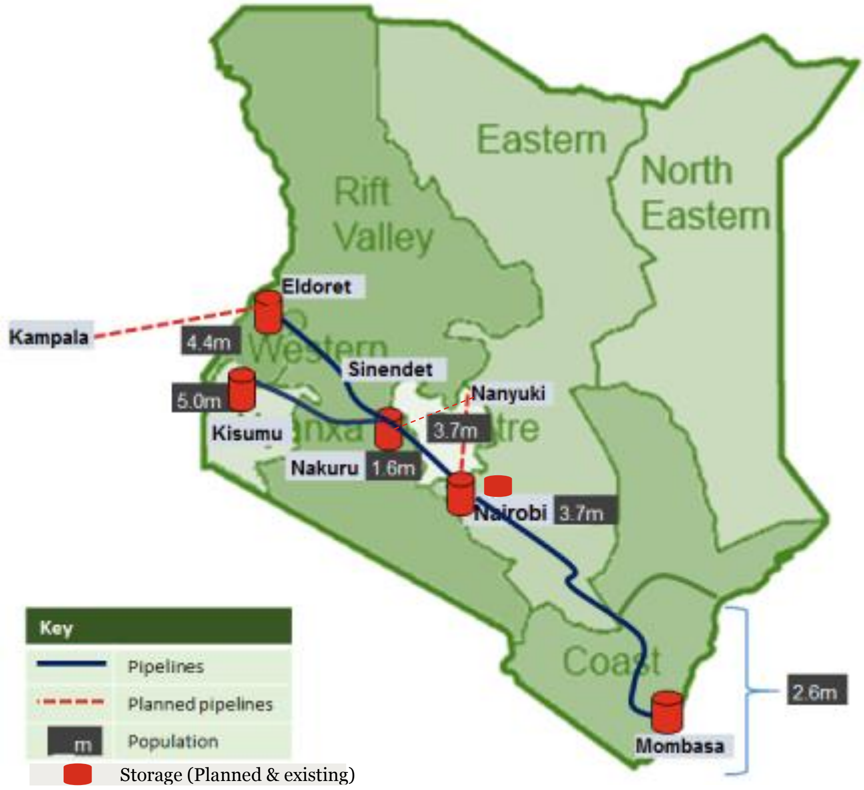
The split of Kenyan product demand and transit volume to the region has been sourced primarily from KPC and PIEA as well as regional market studies to compile the base data and forecasts. The detailed geographic split of Kenyan product demand by region is however not available so the offtake from each major pipeline depot has been used.

As a sensibility check we compared this information to the 2011 population census by County which confirmed the high population concentration along the Mombasa, Nairobi, Nakuru, Eldoret and Kisumu Corridors as reflected below.

*Table 6.5: Kenya population by region*

| Area | Population |
|---|---|
| **Mombasa and surrounding counties** | 2.6 million |
| **Nairobi** | 3.7 million |
| **Central regions** | 3.7 million |
| **Nakuru county** | 1.6 million |
| **Eldoret & Western region** | 4.4 million |
| **Kisumu & Nyanza region** | 5.5 million |

*Figure 6.4: Principal population areas*




*Source: PwC Consortium Analysis*

*Table 6.6: Kenya & transit main product demand – Base case*

| mill $m^3$ | | 2014 | 2016 | 2020 | 2030 | 2040 |
|---|---|---|---|---|---|---|
| **Mombasa** | 10% | 0.5 | 0.5 | 0.7 | 1.3 | 2.5 |
| **Nairobi** | 69% | 3.2 | 3.6 | 4.6 | 8.8 | 17.1 |
| **Nakuru** | 8% | 0.4 | 0.4 | 0.5 | 1.0 | 2.0 |
| **Eldoret** | 7% | 0.3 | 0.4 | 0.5 | 0.9 | 1.7 |
| **Kisumu** | 6% | 0.3 | 0.3 | 0.4 | 0.8 | 1.5 |
| **Kenya Demand** | 100% | 4.6 | 5.2 | 6.6 | 12.7 | 24.7 |
| **Transit Demand** | | 2.0 | 2.2 | 2.6 | 4.1 | 6.5 |
| **Uganda refinery** | | - | - | 1.3 | 2.5 | 2.5 |
| **Net transit Demand** | | 2.0 | 2.2 | 1.4 | 1.6 | 4.0 |
| **Total Demand** | | **6.6** | **7.4** | **8.0** | **14.3** | **28.7** |

*Source: PwC Consortium Analysis*

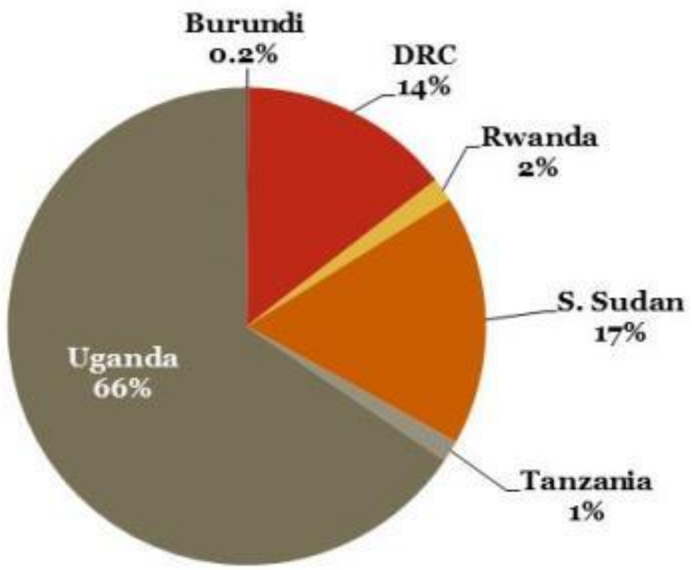
The forecast demand of pipeline fed products has been split based on the current and historical pipeline information.

Nairobi and environs dominate demand at 65 to 70% with Mombasa feeding the port and coastal regions at approximately 10% and the three key towns of Nakuru, Eldoret and Kisumu making up the balance at 21%.

Transit demand is significant at 40% of local demand and is forecast to grow threefold to 2040 based on regional forecasts and information provided by KPC. The timing and size of the proposed Uganda refinery is critical to the infrastructure planning which will be discussed in more detail below. For forecast purposes we have assumed that the Uganda refinery will be operational at 30,000 bpd in 2020 and be upgraded to 60,000 bpd in 2025.

The current split of transit demand is reflected below.

*Figure 6.5: Transit demand– by country (2013/14)*




*Source: KPC, PwC Consortium Analysis*

Uganda at 66% and DRC at 14%, dominate the transit demand as expected, whereas Burundi, Tanzania and Rwanda are low. Rwanda and Burundi are smaller markets whereas Tanzania is supplied predominantly by product imports through Dar es Salaam.

The current exports to South Sudan at 17% of the transit volume are more recent but significant. Cognisance of this will need to be considered in future planning if this trend is likely to continue over the forecast period.

Transit volume is currently uplifted primarily from 3 key depots:

- Nakuru- 25%
- Eldoret- 45%
- Kisumu- 30%

**Total demand (Kenya and transit) is forecast to grow significantly over the period. Forward planning with an understanding of the composition of both the local and transit geographical demand will be fundamental to the development of the required regional infrastructure over the forecast period. This is discussed in more detail in the Commercialisation Routes section below (Chapter 6).**

## 6.2. Oil Downstream Commercialisation Routes, Infrastructure and Operational Requirements

### 6.2.1. Vision

The recent discoveries of indigenous oil have re-ignited the debate about the future of refining in Kenya. The quest to find a commercially attractive upgrade path for the existing refinery at Mombasa has been ongoing for more than a decade, but neither previous oil multinational owners nor recent co-owners i.e. Essar have identified projects that could attract third party funding.

This Study calls for a review of refining options to consider whether recent developments could now allow Kenya to sustain a competitive refining position under free market conditions. Specifically these are:

- the availability of indigenous oil
- the revised supply/demand outlook
- recent or planned changes to regional refining capacity and complexity in the region

Once clarified, the oil product supply chain infrastructure for importing, receipt, pipeline movement, storage and final distribution needs to be reviewed and upgraded to provide the capacity, robustness and efficiency to support Kenya's continued growth.

Successfully implemented, the plan to upgrade this infrastructure should not only serve Kenyan demand but enhance the competitive position of Kenya as the preferred oil transit provider to Uganda and other neighbouring countries for the their oil product import requirements.

### 6.2.2. Specific Challenges

The downstream oil industry which is defined in this Study to include refining, product importing, the oil product supply chain and marketing faces a number of key challenges as it seeks to adapt to forecasted growth and change.

Both the existing refinery and oil product infrastructure is old, of insufficient capacity and cannot meet current requirements. It is already clear that a bold coherent approach to re-generation is urgently required.

A critical factor to support the decision taking required to deliver change is a transparent and sustainable economic platform. The basic requirement is to consistently apply free-market Oil Pricing Policy to crude oil and oil products valuation, and to avoid the use of oil price subsidies which have proven to be expensive, hard to eradicate, and in other benchmarked countries have often supported outmoded practices and behaviours rather than providing a stimulus for change.

A second policy area that the Government will need to address is the 'compulsory stock' policy within Kenya. As Kenya continues to seek investment in its people and economy, the opportunity of any cost of fuel supply shortages becomes an increasing burden both economically and reputationally. Identified best practice approach to target setting, administration and enforcement is discussed in further detail later in this section.

A firm decision needs to be taken regarding the future of the Mombasa refinery. Oil refining margins dependent as they are on small differences between crude oil and on oil product prices, are extremely challenging to forecast short-term with a high degree of precision. However, average returns over the medium term tend to better reflect fundamentals and the factors that impact competitiveness within the region, and the potential of a Kenyan refinery to achieve an adequate return on a free-market basis are discussed in some detail.

Finally, the need to upgrade pipeline and storage capacity and modernise administration, operations and road vehicle distribution is also considered. Much of this new capacity should ideally be created close to the principal consuming areas, though consideration needs also to be given to oil transit capacity to neighbouring countries, and ability to receive the most cost effective imports. Here again, defining the Mombasa refinery's future helps clarify the available tank farms that could be available for re-integration as part of the Mombasa importation and storage complex, and will ensure funds to be spent on new oil receiving facilities at the port are deployed most effectively.

### 6.2.3. Oil Pricing Policy

Historically the oil supply chain was shaped by the global oil's multinationals, whose reach and scale enabled them to gain access to upstream resources and through participation in shipping, refining and marketing businesses establish a presence all the way along the value chain to ensure that wherever value would be captured they would participate. However, over time these vertically integrated businesses became internally focused, rather than seeking to generate improved profitability through customer service excellence and a nimble investment approach.

Many of these vertically integrated organisations set up along the supply chain simply relied upon intercompany transfer pricing to pass costs along the chain. Without these transparent market interfaces, determining where the profits should fall became obscure and impervious to market forces that drive innovation and improvement.

Eventually, shifting patterns of demand and new regulations led to a requirement for change in some sectors, such as small-medium sized refining, which was becoming an increasingly uneconomic business. Rather than facing this reality in a number of countries special allowances for investment, product quality dispensations or intervention on price were used to maintain the integrated supply chain, which shielded the industry and consumers from the true impact of these developments. It is this 'shielding' that fails to drive changes in behaviour which are the natural correcting mechanism of a market-based model.

Given the strategic nature of the oil industry and its fundamental impact on the economies of all countries, there has always been Government involvement in the oil industry. Pricing principles have varied from full regulation of prices throughout the supply chain to the market model that has increasingly been adopted across the world.

A number of key pricing policy lessons were highlighted in the benchmarking analysis:

- Subsidies of and cross-subsidisation between oil products is to be avoided as once implemented are difficult to reverse and costly to Government (e.g. Indonesia and India).

- Development of state owned petroleum assets and the transition to privatised assets is a process that needs to be carefully managed and communicated. There are some key lessons to be learnt in the manner in which Turkey privatized and deregulated the downstream market.

    - *Import parity pricing is a critical initial step which ensures that prices to the consumer are internationally competitive.*
    - *For refinery investment to be credible, such projects need to demonstrate that they are economically viable when compared to the alternative of importing product on a stand-alone basis.*
    - *The scale and complexity of installations required to achieve profitability is increasingly concentrating these investments in global scale industrial centres and regional oil trading hubs.*

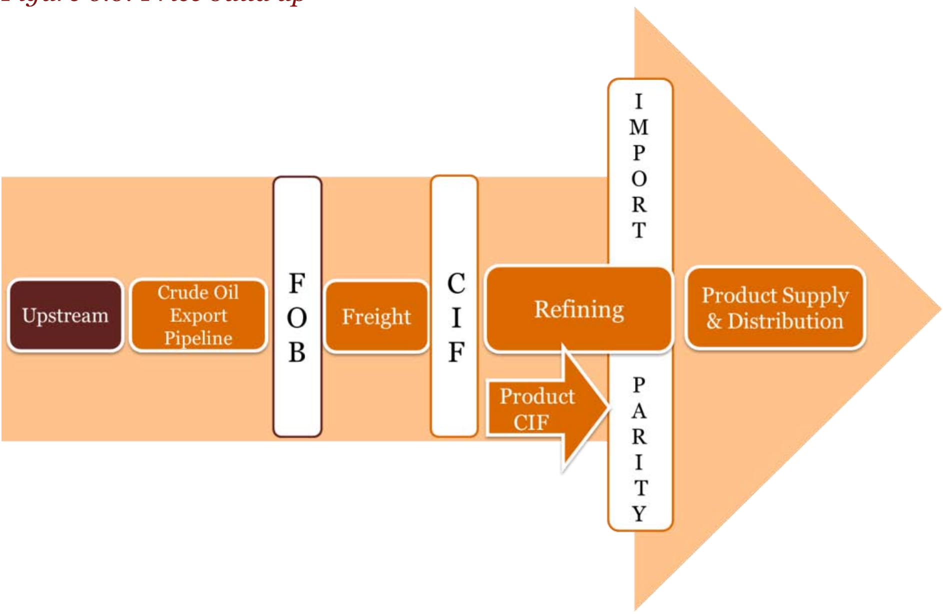
The market-based pricing model enables the profitability of each sector, both upstream and downstream to be readily separated and individually calculated based on independent internationally recognised information:

- The oil market price for crude oil and oil products is based upon reporting of physical cargoes bought and sold around the world, and the futures contracts of the exchanges in London and New York. Reporting companies such as Platt's and Petroleum Argus and others have established widely accepted reputations for accuracy and consistency in their work – so much so that the vast majority of all oil prices are based either directly or indirectly off their quotations.
- The tanker freight /shipping market is set by reference to 'worldscale' – a cost based calculation method. Vessels are categorised into clean (distillate) and dirty (residual oil) and daily market assessments made by Platt's and others in terms of Worldscale points or percentages for each broad size category.
- Where oil product is required at destinations other than quotation reference locations, freight differentials, using 'worldscale' are applied.
- The refinery's margin is assessed on the collective value of the oil products including freight (Import Parity Price), less the cost of crude oil including freight and refinery operating costs.

Further, the market model provides increased value transparency along the chain encouraging independent cargo trading and new entrants. These new players compete in relatively short sections of the value chain, providing competitive alternative offers to consumers. To further stimulate oil supply chain competition, it is important that the infrastructure monopolies are encouraged to compete fairly and that the ERC has proper oversight and power of audit to ensure responsible pricing policies are being followed.

Market based pricing, supported by a strong competition minded regulator, will deliver improved transparency for the investor and greater competitive choice for the customer.

*Figure 6.6: Price build up*




*Source: PwC Consortium Analysis*

# *Pricing Principles by Industry Sector*

### *1. Upstream and Crude Oil Exports*

Monetisation of upstream reserves and construction of the crude export oil pipelines are interdependent activities. These two activities need to be managed as a single business risk and therefore co-ordinated development of the upstream oilfield and development of a viable route to market (pipeline system) is an essential pre-condition if businesses and commercial investors are going to be attracted to these projects.

The investor can assess cost, values and risks knowing that a fair market value will exist for crude oil available Free On Board ("FOB") at the export terminal.

### *2. Oil Refining*

The Pricing model applied to Kenyan refining foresees hydrocarbon costs as follows:

#### a. Crude Oil Pricing

For cargoes supplied by ship the crude oil acquisition price assumption is based upon the import parity price. i.e. the FOB price plus shipping costs (including any losses in transit) to the refinery.

For indigenous pipeline supplied crude oil, if the refinery would be located at or close to the crude oil export terminal the price would be the FOB price.

[***Note:*** *The maximum potential saving for pipeline supplied crude would depend upon freight cost to the principal market. If sold in 1 million barrel ships, sales to Middle East/ India, currently this saving would be US$ 1.00/bbl. So this saving may be realised if both the Kenyan crude was the most economic choice for a Kenyan refinery, and the Kenyan refinery was the best buyer. With so many refining complexes in the region, this outcome is far from guaranteed, and furthermore, the optimal economic choice tends to vary over time, due to the volatility of crude and product prices. Therefore, neither the crude oil producer nor the refiner would want to be structurally limited to this delivery pattern only*].

#### b. Oil Product Pricing

- White Oil or Distillate Products

For a Kenyan refinery supplying product into the pipeline at Mombasa for inland consumption, the product is valued on an import parity basis i.e. the product would be valued on a cargo delivered basis to Mombasa.

If the refinery was located remote from Mombasa, either an additional pipeline tariff would apply or coaster freight.

- Residual or Fuel Oils.

With the declining demand for fuel oil or residual products, an increasing proportion of these black oils will need to be exported over time.

Where the surplus has to be exported, it is valued on an 'export parity' or FOB basis which is equivalent to the Cost Insurance and Freight ("CIF") price at the nearest major consuming market less freight.

This is increasingly impacting hydroskimming margins where some 35-40% of yield is fuel oil. Exporting Fuel oil to the Middle East region bunker market would typically involve freight of US$ 8/T (US$ 1.20/ bbl.).

### Price Comparison Point for Kenyan Fuels

- The internal price comparison point for oil products coming into Kenya should be the delivered Mombasa price, whether imported or refinery production.
- There should be no subsidy applied to either route.

### *3. Pricing to the End Consumer*

Built on import parity pricing for imported oil products, pricing to the end consumer includes duties, taxes, pipeline and storage tariffs, secondary distribution costs and wholesale/retail marketing margins. Kenya is currently a regulated market although there has been significant progress in developing and returning towards a market related pricing system. The monthly Open Tender System (OTS) for product is competitive and an import parity equivalent. The closest logical bulk product pricing source is the Arabian Gulf. Bulk product import prices would generally be referenced against Arabian Gulf (AG) plus freight to Mombasa. Any refining option would need to be able to produce a basket of products with values equal to the equivalent product import parity levels to compete.

Maximum retail prices across the country are set on a monthly basis based on changes in the exchange rate and landed product prices. The tariff for the KPC operated pipeline has not been reviewed over a number of years.

A new strategic storage charge is recommended to be included in the pricing build up to cover the financing charge of holding additional compulsory stocks which is being recommended in this Study in order to provide improved supply chain robustness and pricing stability.

Further, it is foreseen that the ERC which currently oversees the regulation of maximum selling prices would be given extended powers to ensure that wherever a monopoly service is provided the costs or tariffs are fully justified.

The longer-term vision should eventually be to deregulate retail and commercial prices. This could offer consumers greater choice provided there is adequate competition in the marketplace. Under deregulation a competition authority would be required to maintain oversight on competitive behaviour.

## *6.2.4. Kenya Refining*

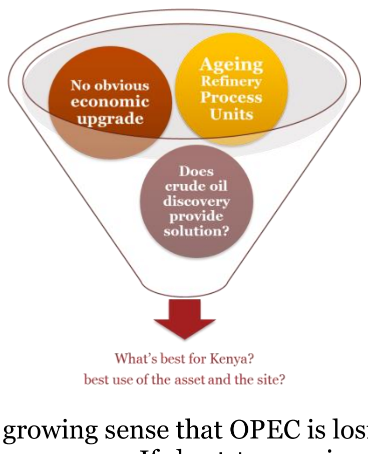
### Historic context

The KPRL refinery in Mombasa was commissioned in 1960. It was originally owned by Shell, BP and Chevron (former Caltex) and intended to serve Kenya and East Africa. In 1970 it received a grease plant, when GoK acquired a 50% shareholding. The refinery was upgraded with a second hydroskimming train (distilling, reforming hydrotreating) in 1974.

In 2009, Shell, BP and Chevron finally sold their remaining interests to Essar, which is in the process of exercising a put option to sell its stake to GoK. No crude oil processing has taken place since September 2013.

### Key decisions -

- Does refining make sense for Kenya for the future?
- Does Kenya continue to have a refinery now or in the future?
- If not what is the best use of the asset and the site?



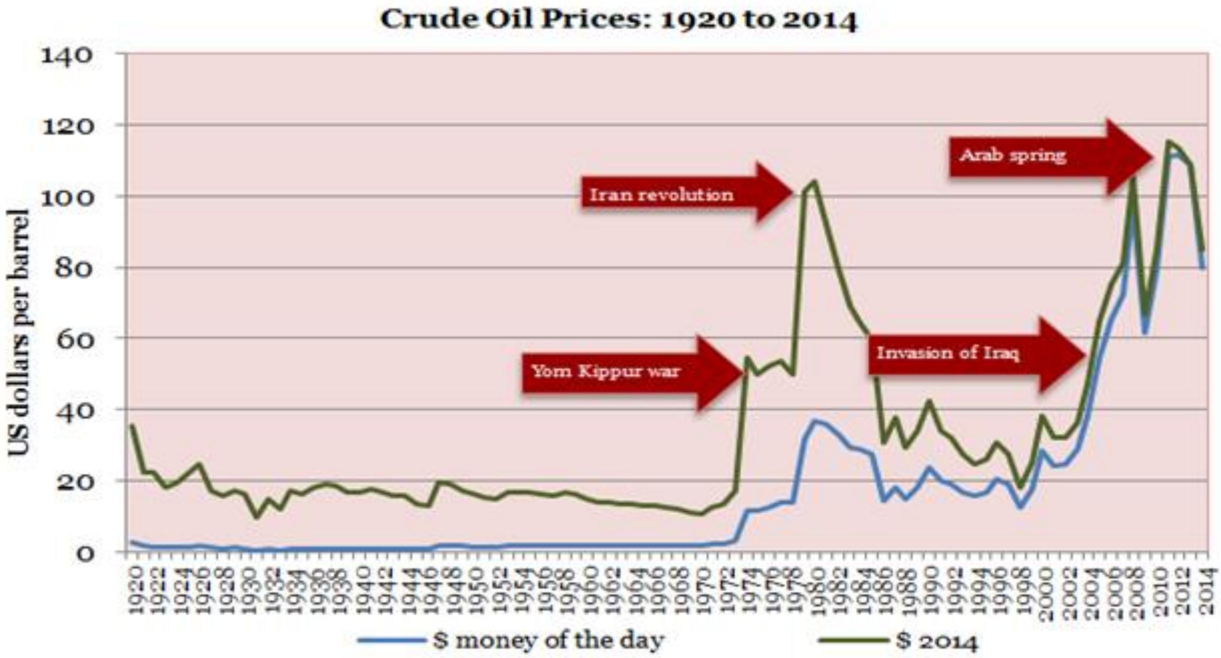

These questions are considered below both within the global, regional and Kenyan context.

### *Global crude and product pricing*

Globally, after many decades of relative calm on the markets the actions of OPEC leaders in the early 1970s ushered in a period of volatility and unpredictability in oil prices that has remained ever since.

Notwithstanding the pressures on supply, demand has reached some 90 Mb/d. Just 2 years ago oil was trading above US$ 120/bbl on concerns about supply security, but the Brent Crude price recently fell below US$ 50/bbl (although had recovered to US$55 at the time of writing) as there is a growing sense that OPEC is losing control of the global supply chain and the spectre of unmanaged oversupply re-emerges. If short-term price movements are almost impossible to predict, it is nonetheless reasonable to assume that medium-longer term, the increasing cost of recovering reserves will eventually put a floor under prices, probably in the US$ 60 to 70 / bbl range. Similarly, alternative energy solutions from sustainable second generation biofuel sources cost significantly more but these should provide a cap to prices in the US$ 150/bbl range (2014 money).

*Figure 6.7: Crude oil prices 1920 to 2014*




*Source: BP Statistical Review of World Energy 2014*

Price volatility must be expected to continue as planned production increases around the world will take several years to be realised. Supply disruptions however, whether unplanned shutdowns, geo-political crises, or unusual weather events all occur on much shorter cycles. The pricing spikes and dips are part of the re-balancing mechanism. Indeed, the increasing use of real-time global communications which facilitates more speculative trading, would suggest that short-term price volatility is likely to remain.

As the vessel sizes for oil product transportation increase, global imbalances can be more cheaply resolved through arbitrage trades, and this trend is set to continue.

Kenya will inevitably be exposed to both the challenges and opportunities that arise from these trends. The key challenges are

- Price Exposure:

If considering a refinery, there's an increasing need for Price Risk Management.

If importing oil products, seek to minimise differences in pricing quotation days between importation and end use.

- Cargo Sizes:

Flexibility to receive 30-160 kt product imports, would make Kenya best place to receive the lowest cost cargo imports, whether supplied locally or inter-regionally.

***The need to keep crude oil trading options open along the supply chain***

The recent discoveries of crude oil in Kenya appear to offer the hope of an integrated oil solution whereby locally produced crude is refined for consumption in the local market. However, although this option has a pleasing simplicity, the turbulent nature of the oil market means that inevitably this solution will not be economically optimal over the long term.

The fact is that over the lifetime of production of an oilfield, or operating life of a refinery, the trading conditions vary considerably. The variation in refining margins as is shown in the next section below, both in outright terms and between geographic regions is considerable and will often exceed the transhipment costs of import and export.

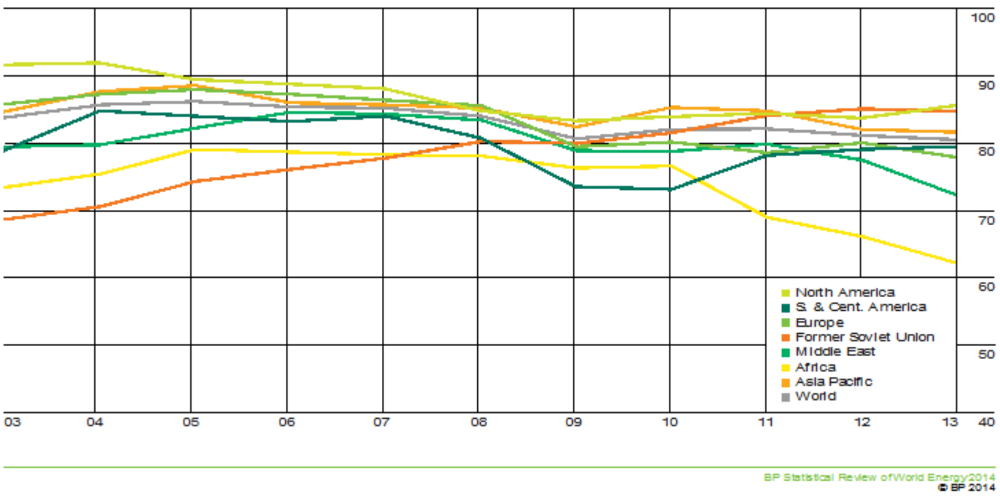
Retaining the flexibility to sell the crude oil production to the highest bidder making a separate economic decision whether to refine or to import finished oil products, and even if refining – allowing the refiner the flexibility to optimise the choice of crude oil and feedstock to process are all fundamental to maximising the value along the oil supply chain. The particularly waxy nature of the Kenyan and Ugandan crude is best suited to higher complexity cracking installations. Limiting its end use to a particular future refinery configuration for Kenya would unlikely consistently optimise its value over the longer term.

So for the overall supply chain from a Master Planning perspective, it is recommended that:

- Indigenous crude oil is all made available for export.
- Any consumption of crude within Kenya is justified by a market price transaction.
- Marketers remain fully free to choose whether to import finished product or purchase from any future refinery.
- The location of any refinery should be coastal since over time both the shifts in the inland balances between refinery supply and market demand, and the opportunity to optimise via trading require ready access to the international oil markets.

***Refinery utilisation and refining margins***

*Figure 6.8: Oil refinery utilisation*




*Source: BP Statistical Survey, 2014*

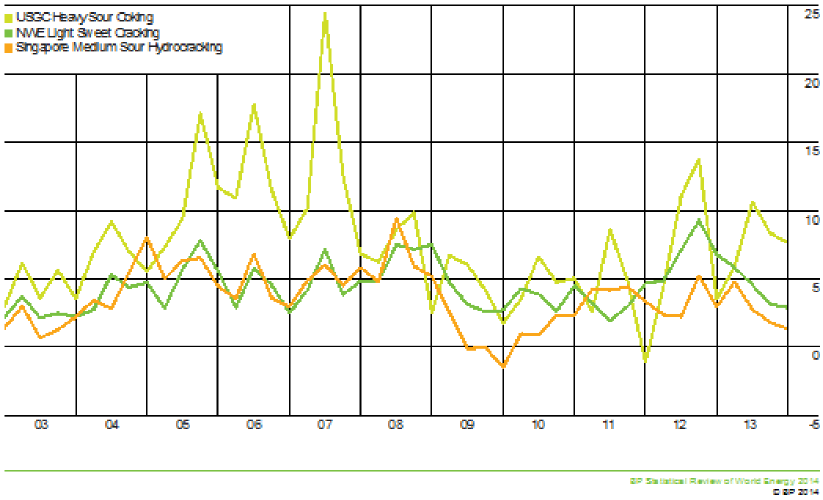
Globally the scale of new refining has outstripped the forecast increasing demand. Although the slowdown has been felt in China, it is in the Middle East where the capacity has been constructed to service this growth where margins are set to remain under pressure.

Refining in the African region in particular, seems destined to come under particular pressure. Already suffering the lowest utilisation rates in the world, and largely based on small hydroskimming facilities, the region is surrounded by increasingly complex refining from Middle East, Singapore, and India.

Furthermore, gasoline export surpluses from Europe which used to supply the US are also targeting Africa. It really would appear that Africa will be targeted as an export opportunity for many of these oversupplied economies for many years to come, and well into the next decade.

Global refining margins are therefore likely to remain weak and in Africa particularly so. As the figure below shows, Singapore hydrocracking margins have not seen US$ 5 per barrel since the 2008 financial crisis. Indeed the average margin over the last 5 years has been closer to US$ 3 per barrel.

*Figure 6.9: Regional oil refining margins*




*Source: BP Statistical Survey, 2014*

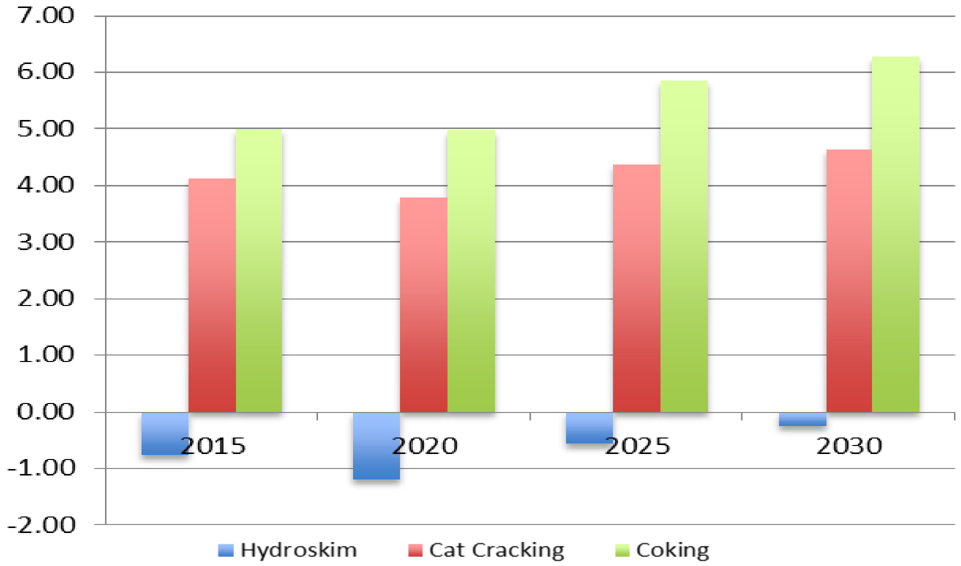
Over the Master Planning period of 2015 to 2040, our own forecasts predict hydroskimming margins to remain negative whereas both catcracking and coking gross margins recover to US$ 4 to US$ 5 per barrel. The outlook over the 2015-2025 period seems particularly poor with regional overcapacity capping any potential upside for the next decade.

Full cost refinery economics were estimated on a 200 kb/d facility. Although double the current requirement for Kenya and surrounding transit markets, this represents a mid-point for the Base Case demand which quadruples over the planning period to more than 400 kb/d by 2040.

For modelling refinery margins, a matched data set for crude oil and products has been taken, with the reference price of crude oil at US$ 100 per barrel. Despite this recent major slump in oil price, there is no current belief that the fundamentals for refining have changed in any structural way, and the outlook remains one of intense competition and capacity oversupply in the Middle East/Africa region.

Our assumptions are that cracking/coking gross margins will be on average US$ 4 to 5/bbl over the period to 2030. For a new greenfield 200 000 bbl/d refinery, we estimate cost of a cracking or coking refinery at approximately US$ 4b or US$ 5b respectively.

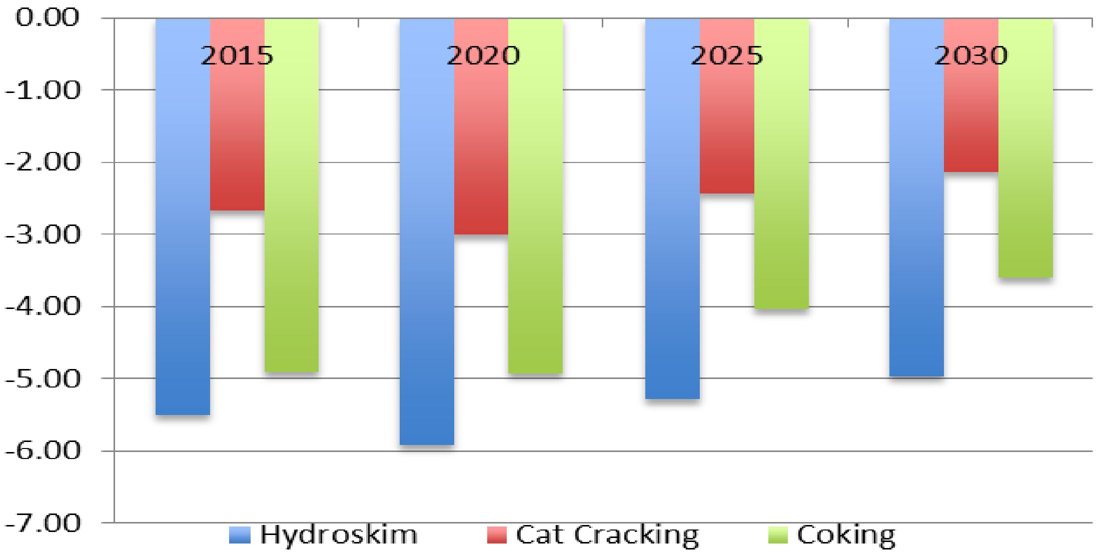
*Figure 6.10: Refining gross margins 2015-2030 (US$/bbl)*




*Source: Channoil Analysis*

On an ungeared basis, and assuming a conservative 10% return on capital, the full cost margins at these refineries will still fall US$ 2/bbl to US$ 3/bbl short of the minimum required return on investment as reflected in the figure above.

*Figure 6.11: Full cost margins (*WACC 10%) on 200 kb/d (US$/bbl)*



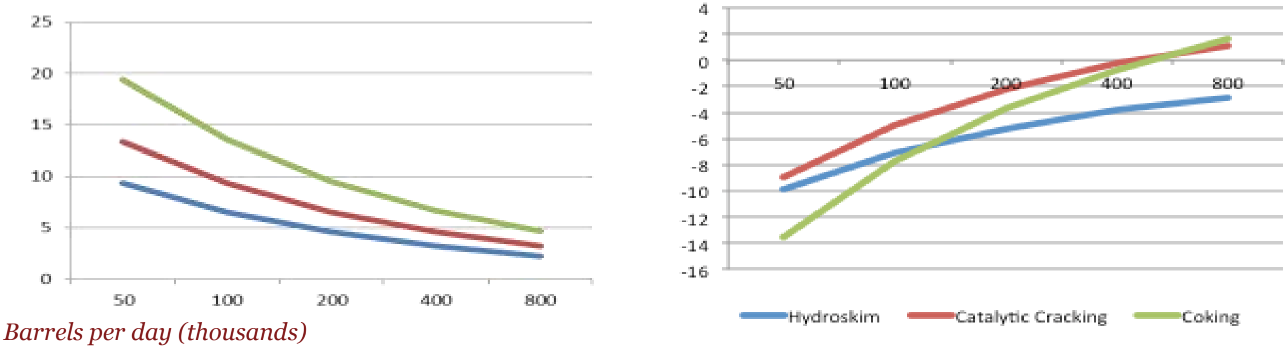

** Weighted Average Cost of Capital (WACC)*
*Source: Channoil Analysis*

Other than refinery complexity, the major factors affecting refinery profitability are:

- **Economies of Scale**. Planning guidelines indicate that in doubling the size of a refinery, costs only increase by 70%. Thus as capital costs rise with the increasing complexity required to achieve high distillate yields demanded of modernising economies, so the US$/barrel incentive to increase scale becomes even greater. As the figure above shows, the full cost margin requirement for a cat-cracking 200 kb/d refinery falls by some US$2 per bbl if scaled-up to 400 kb/d. Since, as has been discussed in the oil pricing section 6.2.3 that the location advantage for a refinery running indigenous crude and supplying the inland market is unlikely to exceed US$ 2/barrel, we can infer that the modern Middle-East refineries of 400 kb/d could fully compete a similar 200 kb/d facility built in Kenya.

*Figure 6.12: Refining economies of scale (US$/bbl)*

**Operating cost comparisons** | **Full cost refining returns**



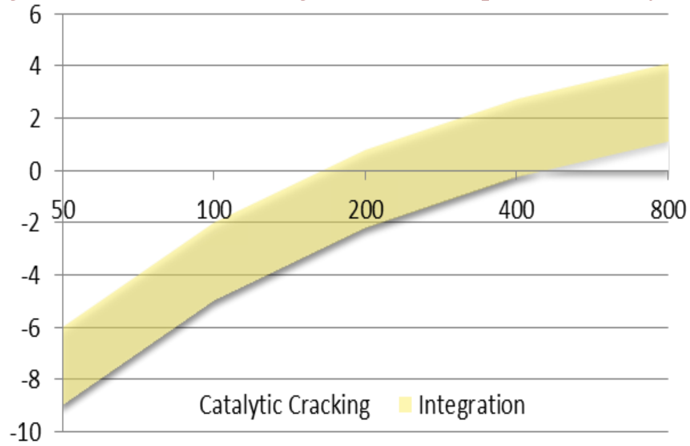

*Barrels per day (thousands)*

*Source: Channoil Analysis*

- **Chemicals Integration**. This approach lies at the heart of strategic refining investments over the last decade made by oil majors such as Shell and Esso (Esso Singapore shown below), who have integrated their chemical steam cracking facilities with oil refinery processes, allowing not only operating costs optimisation, but yield optimisation too. These cost synergies/added gross margin, are estimated to be worth some US$2 to US$5 per barrel depending on the specific installations and market conditions. Where this oil-chemical integration can be achieved, there is the potential to make attractive returns from refining.

  This type of opportunity is realistically only available at major industrial centres such as the US Gulf, Rotterdam, Singapore but is destined to become a feature of many Middle East complexes too. However, the Kenyan market has neither the scale, nor complexity to directly compete, nor is it sufficiently remote to operate as a locational niche.

*Figure 6.13: Chemical integration and its potential benefits (US$/bbl)*

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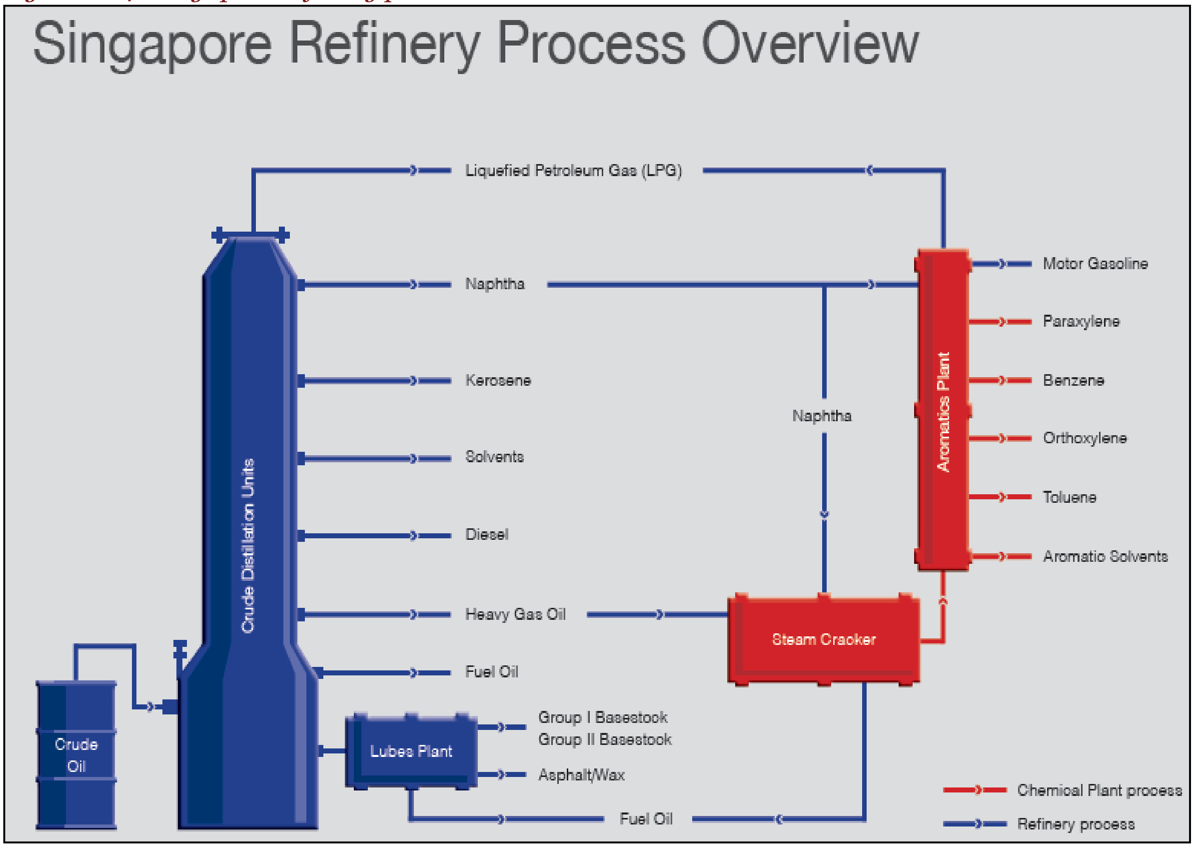
*Barrels per day (thousands)*

*Source: PwC Consortium Analysis*

*Figure 6.14: Singapore refinery process overview*




*Source: Exxon Singapore*

- **Middle East Refinery Expansion**. The principal refinery margin competition for any new Kenyan refinery will come from the Middle East where a huge programme of construction amounting to some 2.2 million b/d is under way. Originally conceived when Far Eastern oil demand was expected to grow more rapidly than current estimates, these huge refining/chemical complexes are strongly supported by countries with huge reserves of low cost indigenous oil, and are very well placed to cope with periods of weak margins until global growth restores the balance. This anticipated overhang of world scale class leading refining complexes is expected to progressively force the closure of the weaker more simple refineries from North West Europe to Singapore.

*Figure 6.15: Middle East refinery expansion*


*Source: PwC Consortium Analysis*

Against this background, we believe that commercial investors are unlikely to be persuaded to invest in greenfield small/medium sized refining in Africa – probably for at least the next decade.

**Refining in conclusion:**

1. Forecast refining margins look challenging for the foreseeable future. While gross margins may justify the continued operation of medium and larger cracking and coking units, gross margins for existing hydroskimmimg units such as KPRL Mombasa are predicted to be zero or negative over this timeframe, and **would be loss making versus imports (Import parity pricing)**.

2. Full cost refiner's margins (including an investment return of 10%) only start to justify the capital expenditure at a scale well in excess of 200 kb/d and only then provided the resultant products are absorbed by inland demand. For Kenya, the high diesel use (> 60% of total demand) and the foreseen collapse in fuel oil demand implies cracking and eventually coking technology will be required to produce the required product yield. If constructed at a new greenfield location, such a refinery is estimated to cost US$ 4-5 b for a 200 kb/d facility.

3. World class refining complexes are increasingly integrated with chemical production, and the resultant efficiencies typically exceed US$ 2/bbl, which allow these integrated complexes to outcompete a local cracking refinery of similar size.

4. Currently the Kenyan and surrounding transit markets combined demand is below 100 kb/d. Kenya has neither the market scale nor industrial complexity to support a class leading refining complex capable of competing with the best in the region.

5. Whilst the market remains long in capacity, **Kenya's best economic interests would be to avoid refinery capital expenditure**, and focus on becoming an efficient importer of oil products, with a robust supply chain capable of supporting Kenya's growing fuel requirements with secure, lowest cost, modern specification fuels and using this platform to further its interests as a pipeline transit supplier to neighbouring countries where there is a sound economic basis.

6. Notwithstanding the rather bearish outlook for refining set out above, given that margin forecasting is not really credible beyond 2030, it may still make sense to earmark a potential future location within

the Master Planning framework and to review the situation around 2025, by which time the regional refinery oversupply may be coming back into balance, indigenous oil production potential will be clear and even new technologies may have created possibilities which cannot currently be foreseen.

## *Recommendation for Kenyan refining:*

Accept the bearish short/medium term outlook **to 2025** for refining and convert KPRL to an import terminal.

(This may require a final review by GoK of the rationale provided by KPRL of the comparative economics and capital investment for upgrading the refinery before proceeding)

This will include:

- Clearing the site process units and reconfiguring tankage to meet current and future requirements.
- Implementing a coordinated plan with Mombasa Port and KPC to optimize storage and pipeline configurations.
- Identifying land near the crude oil export terminal for any future refining site.

**Beyond 2025**

Although still expected to be uneconomic, given the forecast scale of Kenyan demand and potentially new technologies may justify a review of the refining option beyond 2025.

## *6.2.5. Kenya –Compulsory (Strategic) Oil Stock Policy*

**Introduction**

The provision of an adequate reserve of oil stocks held at suitable locations in country, which can be brought into use at short notice is critical to assure continuity of the transportation links on which all modern economies depend, whether for industry, commerce or private mobility.

A suitable strategic stockholding ensures that a country can continue to function in times of supply disruption howsoever caused.

Holding a suitable level of strategic stockholding generates a level of confidence that maintains normal behaviours during times when the supply chain is stressed, avoiding hoarding, panic buying or predatory pricing practices.

Currently it is estimated that the country holds between 5 and 15 days product stock in tank which is insufficient in the event of a major supply disruption.

**Global Energy Policies**

The International Energy Agency (IEA) Policy requirement, for its 28 member states is for 90 days of net importing requirement to be held in country, which is adjusted for crude exporting countries such as United Kingdom, Denmark, Norway and Canada. The European Union also requires members to hold 90 days of compulsory stocks. Other developing countries are building oil reserves, such as China that aims to achieve 90 days by 2020.

Another approach has been to form Emergency Oil Sharing Alliances such as Japan, New Zealand and South Korea, who have defined terms under which they would sell reserves to each other in an emergency.

**Imposition of the Obligation**

Individual country mechanisms for meeting their compulsory stock obligations vary by country. In some cases these stocks are Government owned, in others the obligation is placed upon industry by the Government. Many others rely on a mixture of state and private obligations.

**Financing the Obligation**

The cost of renting the storage and the interest charges of the cost of product are normally defined by the Government and allowed as a supplementary charge on the final consumer price. Should Compulsory Stock

Entities (CSEs) be set up to administer compulsory stocks and compulsory stock charges, they would be responsible for proposing the level of supplementary charge to the ERC for approval and consolidation.

However, who should take the price risk on the change of market value of compulsory stocks depends upon the ownership structure, and it is recommended that GoK should consult with the oil industry before finalising a preferred approach. The key issue is whether GoK or industry should carry the risk of fluctuation in stock value.

**Control of Compulsory Storage and Stockholding**

Compulsory stocks can be either held at Government owned storage facilities, held in dedicated CSE's or held by the oil industry itself and declared to Government as available for compulsory stock.

Other countries which had favoured putting the obligation directly on the oil industry to hold the required level of strategic stocks at their terminals, such as the UK are now considering the use of a single Agency or CSE, usually an independent, not for profit organisation operating under a Government mandate to assure a more coherent approach to compliance. Examples of Agencies with long established reputations for successful administration and control of compulsory stocks are EBV (Germany), Sagess (France) and Carbura (Switzerland).

A recent review carried out this year in the UK where the Government currently relies on industry, appears to favour a switch to a CSE. This is an independent, not for profit agency. The normal approach is to require all industry players to meet their obligations through the single CSE. A CSE may in turn rent or build storage in country in order to ensure sufficient capacity to meet the country's needs.

**Enforcement**

All storage declared for compulsory stock purposes requires regular audit for quantity and quality. This process is made easier through the use of CSE's, who act as a national focal point for administering the physical stocks.

**Setting Compulsory Stock Target for Kenya and the Oil Product Pipeline system**

Whilst alignment to the 90 day IEA strategic stock targets would position Kenya with an extremely robust position, the cost of financing 90 days of oil products is a heavy additional burden on the country, and needs to be both carefully considered and built up gradually.

Taking into consideration Kenya's geographic position we would suggest that finished products be built up from its current level of 5- 15 days to 40 days stock and maintained at this level. This would provide a higher degree of supply security than most of Africa. These stocks would ideally be located both at the point of importation and in the proximity of their local demand.

In setting Kenya's compulsory stock targets some of the factors to be considered include:

- **Geographic location** - the key question is how many days would it take to secure and receive product stocks into tank in Kenya from the nearest reliable realistic source. A number of options were considered:
    1. Product ex the major export refineries of the Arab Gulf States and West Coast of India or through the major traders currently used for the monthly OTS (open tender system). It is estimated that this would be possible to obtain product within 25-30 days based on 7- 10 days shipping time plus 20 days for organisation, loading and clearance.
    2. If portion of the product had to be sourced from the next major sources of Singapore and Russia the lead time for shipments and securing product is likely to increase to 30 – 45 days given the distance.
    3. If product had to be sourced globally from the US Gulf Coast, Rotterdam, or the Far East this would increase the timing, particularly if dealing with new sources to between 45 to 65 days based on sailing time from the Gulf of 45 days and 20 days from Rotterdam.

  Given the countries relatively low oil product demand in global terms, acquiring 40 days compulsory product stock would be equivalent to approximately nine 50 000 tonne ships based on current demand . This should be easily sourced from the export refineries of the Arab Gulf or India. Thus 40 days stock should provide the required buffer based on current timing and access to the Gulf.

- **Refinery closure: Strategic stock for pipeline system** - if the refinery closure is taken into account, some 20 days of stock held as crude oil, intermediates and finished stock needs to be replaced.

Holding the same quantity of finished stock instead at Mombasa would provide equal or better security, and could be made available more quickly.

- **Local strategic stocks -** in the event of a break down in the supply chain it is recommended that a proportion of the compulsory stocks be located close to the end consumers. This could be typically a further 15-20 days of finished stocks.

- **Maintaining integrity of transit supplies across Kenya** – transit volumes currently account for some 30% of all movements along the oil product pipeline from Mombasa to Eldoret. To provide the same level of supply security to export locations, it is considered appropriate that countries receiving transit product also hold stock for the pipeline system (it is assumed that transit countries would make their own arrangements for local strategic stocks).

The numbers of days of product stock that GoK decides to hold as strategic stock is essentially a judgement call based on the perceived level of risk of a product stock out and the implications for the Kenyan economy compared to the cost of investment in tank capacity and the holding cost of the product stock.

As product demand grows over the period the volume of strategic stock increases as does the required tankage capacity which has been based on the 40 days base case as illustrated in the table 6.7 below with an increase from the current requirement at 40 days of 0.5 million m3 in 2014 to the forecast 2.7 million m3 in 2040 at a forecast total cost of US$ 657 million.

The working capital cost of holding strategic stock is generally determined as the financing cost of holding the stock as it is considered to be an asset that banks will finance as it is a tradable commodity. We have assumed the cost of financing to be 10% p.a. of the product value which has been based on US$ 100 crude equivalent. This is forecast to cost US$ 68m in financing charges increasing to approximately US$ 339m in 2040.

*Table 6.7: Compulsory stocks target – impact on tankage capacity and working capital*

| | | | **2014** | **2016** | **2020** | **2030** | **2040** | **US$ millions** |
|---|---|---|---|---|---|---|---|---|
| Compulsory stock tankage capacity | | **mill $m^3$** | **0.5** | **0.6** | **1.0** | **1.4** | **2.7** | **$657** |
| | | | | | | | | |
| Compulsory stock product | **40 days** | mill $m^3$ | 0.5 | 0.6 | 1.0 | 1.4 | 2.7 | |
| | | | | | | | | |
| Holding/financing cost (@10% interest) | **40 days** | $mill | **$68** | **$76** | **$93** | **$170** | **$339** | **$339** |

*Source: PwC Consortium Analysis*

## 6.2.6. Mombasa Importation Hub

The Master Planning approach to Mombasa oil facilities assumes the KPRL refinery processing operations are shut down and the facility is converted to an oil storage facility.

The key to transforming the effectiveness of Mombasa as an oil import and storage facility is to network together the physical oil receiving facilities at the port, the storage and handling facilities of KPRL, OMC's and KPC and co-ordinate the overall management of hydrocarbon flows from importation planning, customs clearing and administration, storage (including compulsory storage) and pipeline scheduling of inland and transit batches.

The vision for the hub is that it should provide:

- Discharging capability for vessels up to 200k tonne and a separate smaller facility for up to 50k tonne vessels.
- Receiving facilities and tank ullage sufficient to allow discharging operations to be completed in 24 hours – this eliminates structural demurrage. Planned tank capacity of 20 days.
- Excellent pipeline connectivity between tank farms of the hub to allow unconstrained operations.
- Good pipeline connectivity to the oil product pipeline operated by KPC.
- Compulsory storage component of 20 days stock to support supply robustness of the Kenyan oil product pipeline.

- Enabling fiscal environment to allow for trading.

The recommended approach to Master Planning of the importation Hub is to bring together the following entities in order to make detailed plans. Specifically these are:-

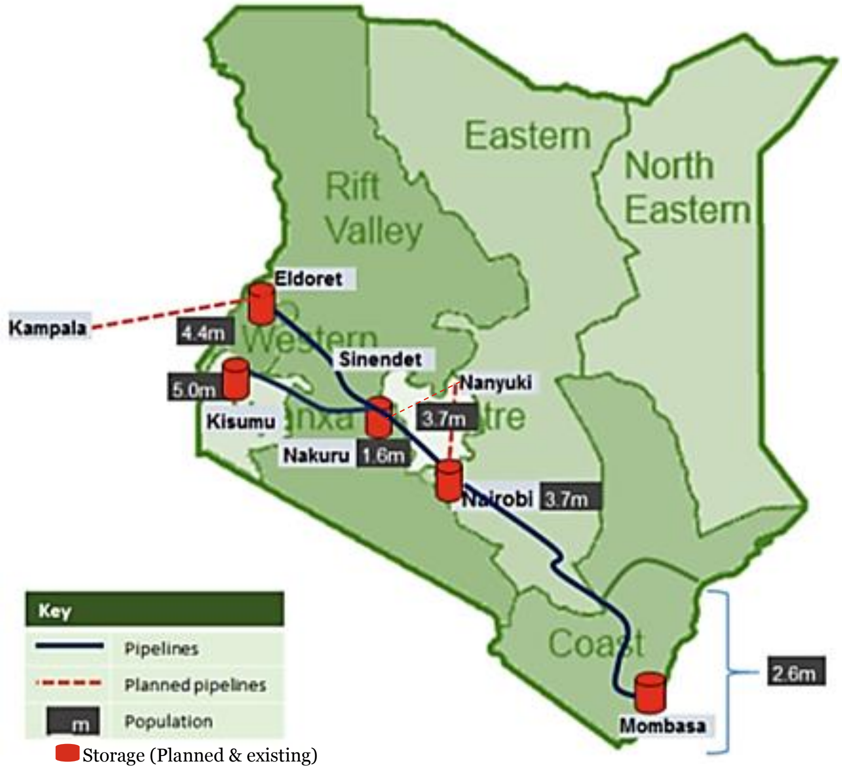
- KPA
- KPC ("KOSF")
- PIEA ("SOT")
- KPRL
- KRA
- NOCK

**The scope of the integration exercise will be to:**

- Determine the optimal integration of existing tanks in the Mombasa area to meet future country, local and transit requirements, based upon this Study's Base Case recommendations. The detailed requirements will include the required discharging ullage by grade, operating stocks, local and national compulsory stocks. There is a need to ensure that there is more than one offloading facility to ensure security of supply. It is envisaged that it will incorporate a SBM facility.
- Identify the land and logistic requirements to provide sufficient tank capacity, in a well ordered, efficient and secure facility.
- Develop the compulsory product storage element, which is provisionally assumed to occupy the KPRL site. This would require an expansion plan consistent with Kenyan demand growth and transit volumes.
- Provide facilities capable of performing in line with the Vision statement above.
- Provide a pre-FEED estimate of the capital cost and necessary resources required to deliver the change.
- Create a co-ordinated and controlled administrative environment that ensures cargo imports are properly scheduled, clear customs efficiently and are routed to pipeline.

## *6.2.7. Storage facilities and the need for expansion*

*Figure 6.16: Pipeline fed terminals*




*Source: PwC Consortium Analysis, KPC Information*

As can be seen from the figure above, the principal existing storage facilities, which are connected via the KPC pipeline system are well located in the main areas of demand. However, these terminals will need significant upgrading to cope with additional capacity requirements rising from (i) a forecast 4-5 fold increase in demand by 2040, and (ii) the recommended strategic storage policy that envisages 20 days stock to be held local to the main demand centres.

**Nationally**

Nationally, the plan calls for an expenditure of US$ 1.3b providing some 5 million $m^3$ of additional capacity (see Table 6.8) over the period to 2040. The majority of this expenditure is forecast to takes place from 2031 to 2040, as the cumulative impact of growth puts pressure on the required storage capacity.

The proposed integrated stock policy for Kenya is based on the following premise:

1. Compulsory stock policy and tankage capacity of 40 days strategic stock based on Kenya oil demand held as follows:
   - Nationally 20 days stock held at the import hub of Mombasa.
   - A further 20 days stock held locally at the key distribution centres of Mombasa, Nairobi, Nakuru, Kisumu and Eldoret.

2. Operating stock and tankage capacity requirements has been based on both Kenya oil demand plus transit demand and has been forecast to be held as follows:

- An additional 20 days tankage capacity to cover ullage at Mombasa so as to ensure sufficient tankage capacity to allow ships to offload without waiting for capacity availability and incurring demurrage costs. Thus tankage capacity is 20 days greater than product stock.
- 20 days operating tank capacity at the regional distribution centres to ensure efficient distribution operation.

In order to provide a firm platform for expansion, given the age of the existing facilities and concerns expressed in recent terminal technical audits that estimated as much as 60% of existing tankage is in need of major refurbishment, it is proposed that an accelerated programme of refurbishment takes place within 3 years to restore all tanks destined for long term use.

**Nairobi**

For Nairobi, which accounts for almost 70% of Kenyan demand, it is recognised that the existing facilities are under capacity, and already some 132,000 $m^3$ in road fuel storage and 70,000 $m^3$ of airport storage is being installed by KPC.

However, substantial further improvements will be required, and there are two new terminals that are envisaged to cope with the planned demand growth. These new facilities should be located well to the North and East of Nairobi, with positioning to take account of future urban development in and around Nairobi, the airport, and planned road programmes. The overall capacity of each of these new depots would be some 400,000 $m^3$.

**Mombasa**

At Mombasa although significant storage capacity already exists, it is proposed that longer term, as demand increases a new terminal is constructed on the mainland in the vicinity of the main Mombasa – Nairobi highway and pipeline system so that the depot can efficiently service localised demand within the regions adjacent to Mombasa.

**Kisumu**

At Kisumu, a major upgrade of the waterborne facilities is required, so that barge loading can become a direct pipeline fed operation, and that the mooring facilities provide for rapid, safe, secure loading avoid undue waiting times. It appears likely that once upgraded, Kisumu may attract substantial incremental business from around the shore of the lake.

**Eldoret**

The storage and road loading facilities have recently been upgraded to meet increasing export requirements. Although local demand is set to steadily increase, there is some uncertainty regarding future transit volumes. This Study's base case assumes a reduction of 1.25 million $m^3$ in transit demand from 2020, as the Ugandan refinery comes onstream, initially at 30,000 b/d, and reduction of a further 1.25 million $m^3$ from 2025. Even so, transit volume still increases from 2.0 to 4.0 million $m^3$ over the planning period to 2040.

Our understanding is that the Ugandan refinery is a strategic requirement of a country that has recently discovered crude oil and that is landlocked. Should the refinery generate either gasoline or gasoil surpluses, in addition to meeting Ugandan demand, these could potentially compete with imported Kenyan product at the border. However, since imported product for Kenya is expected to be cheaper than refined Ugandan product, and market prices will be higher further inland towards DRC or South Sudan, it appears unlikely that the refinery would cause either price or additional demand erosion at the border, beyond that assumed in the table below.

*Table 6.8: Terminal operational and compulsory capacity requirements*

| **Forecast Terminal capacity requirements - assuming Uganda refinery operational from 2020** | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | ***mill m³*** | **2014** | **2015** | **2016** | **2017** | **2018** | **2020** | **2030** | **2040** |
| **Net offtake** | Kenya | 4.6 | 4.9 | 5.2 | 5.5 | 5.8 | 6.6 | 12.7 | 24.7 |
| | Transit | 2.0 | 2.1 | 2.2 | 2.3 | 2.4 | 1.4 | 1.6 | 4.0 |
| | **Total** | **6.6** | **7.0** | **7.4** | **7.8** | **8.2** | **8.0** | **14.3** | **28.7** |
| | **days** | | | | | | | | |
| **Operational Capacity- held at key inland centres** | 20 | 0.4 | 0.4 | 0.4 | 0.4 | 0.5 | 0.4 | 0.8 | 1.6 |
| **Operational capacity-held at Mombasa** | 20 | 0.4 | 0.4 | 0.4 | 0.4 | 0.5 | 0.4 | 0.8 | 1.6 |
| **Operational Capacity-Days** | **40** | | | | | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Compulsory Capacity- held at Mombasa** | 20 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 | 0.7 | 1.4 |
| **Compulsory Capacity – held at key inland centres** | 20 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 | 0.7 | 1.4 |
| **Compulsory Capacity- Days** | **40** | | | | | | | | |
| **Total** | **80** | **1.2** | **1.3** | **1.4** | **1.5** | **1.5** | **1.6** | **3.0** | **5.9** |
| **Current Terminal Capacity** | | 0.9 | 0.9 | | | | | | |
| **New Capacity Required** | | **-** | **0.2** | **0.3** | **0.3** | **0.1** | **0.1** | **1.0** | **3.1** |
| **Total forecast capacity** | | 0.9 | 1.1 | 1.4 | 1.7 | 1.8 | 1.9 | 2.8 | 5.9 |
| **New capacity *$ mill*** | **$1,315** | **-** | **$24** | **$94** | **$130** | **$30** | **$15** | **$254** | **$768** |

*Source: PwC Consortium Analysis*

The individual terminal capacity increases are detailed in the table below. The increases will enable both sufficient operating capacity of 20 days, and a further 20 days of capacity to be used for the holding of compulsory stocks to be held at each location.

The table below sets out the timeline for the proposed capital expenditure to support the new capacity to be built, and a forecast of the capital expenditure required to deliver the required network expansion.

*Table 6.9: Planned new terminal capacity*

| Planned new terminal capacity | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| ***mill $m^3$*** | **Current** | **2014** | **2015** | **2016** | **2017** | **2018** | **2020** | **2030** | **2040** |
| **Mombasa** | 0.65 | - | - | 0.22 | 0.27 | - | - | 0.30 | 1.70 |
| **Nairobi** | 0.15 | - | 0.18 | 0.10 | - | - | - | 0.63 | 0.60 |
| **Nakuru** | 0.03 | - | - | - | - | 0.06 | - | - | 0.24 |
| **Eldoret** | 0.05 | - | - | - | - | 0.06 | - | - | 0.24 |
| **Kisumu** | 0.05 | - | - | - | - | - | 0.06 | - | 0.24 |
| **TOTAL** | | **-** | **0.18** | **0.32** | **0.27** | **0.12** | **0.06** | **0.93** | **3.02** |
| **New capacity *$ mill*** | **$1,315** | **-** | **$24** | **$94** | **$130** | **$30** | **$15** | **$254** | **$768** |

*Source: KPC, PwC Consortium Analysis*

**<u>New Depots:</u>**

- **Lamu:** A sea-fed depot at Lamu of 20,000 $m^3$ is proposed from 2020. This is to support planned developments along the LAPSSET corridor and is included in the planned new terminal capacity plans.
- **Nanyuki:** Nanyuki, a rapidly growing town which lies on the main route from Nairobi towards Ethiopia in the vicinity of Isiolo, is a location under consideration for connection to the KPC pipeline system. If connected, it would provide a suitable entrepot depot for road bridging into North East Kenya.

**Existing Road Supplied Country Depot's**

The OMC's operate some 40 small country depots with storage capacities of less than 10,000 $m^3$ and more typically less than 2,000 $m^3$. It has been forecast that rural oil demand growth will be 50% of urban expansion which would result in throughput volume doubling over this period.

In all cases, this would be insufficient to justify pipeline connection, so road bridging from the closest pipeline fed depot remains the most appropriate means of re-supply. Minor upgrades to these individual facilities will remain for OMC's to consider based on local circumstances.

**Distribution**

Gantry Updating and Automation. The product loading facilities at gantries will require a program of modernisation to meet recognised international oil industry standards. Specifically, this involves:

- A switch to 4 inch 'dry break' couplings that allow the driver to fill and discharge fuels at ground level. These systems are faster loading than the old 3 inch top loading systems, and are safer for the driver. Where required, installation of updated gantry automation systems that ensure managed product delivery, payment security stock control and customer billing are efficiently carried out.

  *(Note: these upgrades require early advice to customers, who may need to update their distribution vehicles to have compatible loading nozzles and automatic high level cut-off devices fitted to the loading tanks.*

**Managed Supply Chain Administration**

In addition to physical tank, pipeline and gantry loading facilities to achieve a high degree of operational efficiency, a properly controlled and managed end-to–end process of administrative control needs to be introduced. This will encompass the entire hydrocarbon flow from planned shipping arrivals, through receipt, customs clearance, storage, pipeline scheduling, terminal stocking and product distribution.
Specifically, it will support a shift to better customs clearance procedures (where bulk clearance and proper supervision should replace individual clearances) and customer credit control (to avoid last minute clearances).

Managing the entire flow using a single robust computer system, has the potential to transform oil movement efficiency, enabling product flows to move quickly and efficiently to the required location, and waiting times for truck loading, which are on average 5 hours per loading to be drastically reduced.

Other distribution changes that will streamline deliveries include changing customer charging calculations to favour full vehicle drops and 24 hour delivery patterns. These should be consolidated into the change process as part of the administrative modernisation.

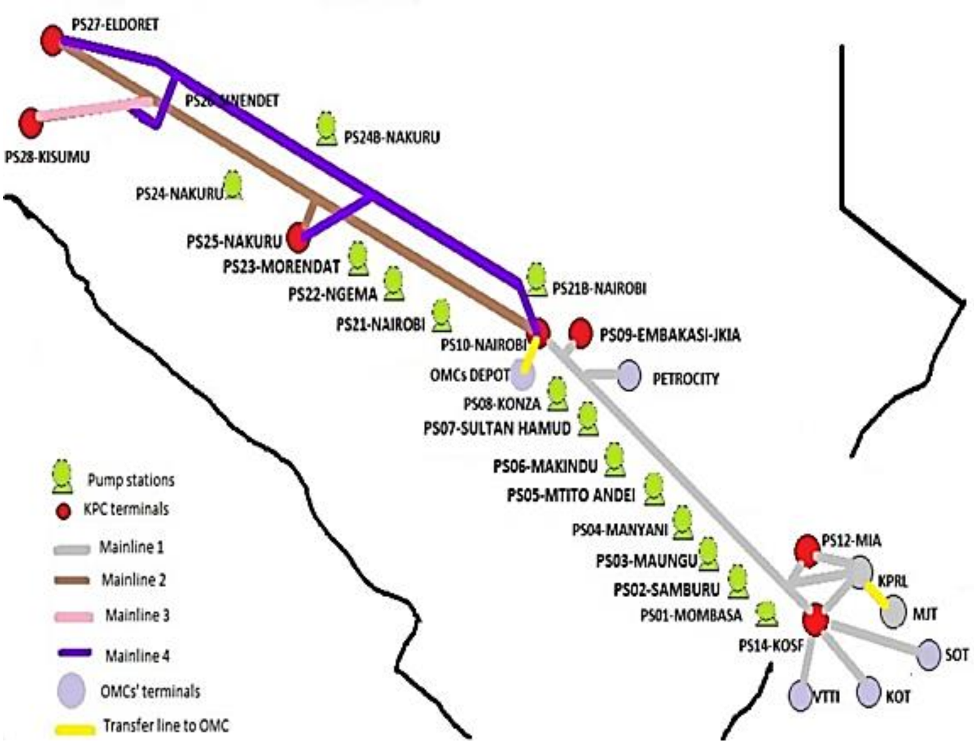
## 6.2.8. Kenya and Regional Pipelines

Pipelines are the most cost effective mechanism of moving oil products in bulk over long distance and are a fundamental component of the petroleum product distribution system. This is particularly important in Africa where rail transport, which is the next cheapest alternative, has been limited or in need of upgrading and infrastructural investment.

Kenya has a developed product pipeline system which covers over 1,200 km following the major cities and towns from Mombasa, through the major hub of Nairobi to the towns of Nakuru and Eldoret with a spur line to Kisumu as depicted in the figure below.

Nakuru, Eldoret and Kisumu are the key locations for the uplift by road of transit volume to neighbouring countries. The projected future transit volumes are fundamental in decisions on the extension of the current pipeline from Eldoret to Uganda (Kampala) and beyond and are discussed in more detail below.

*Figure 6.17: Kenya's current pipeline structure*




*Source: KPC Information*

The pipeline system and major storage terminals are owned and operated by Kenya Pipeline Corporation a parastatal owned 100% by GoK. Discussions have been held with stakeholders, in particular KPC and PIEA to consider the current and planned developments with the objective of ensuring that the country has the required pipeline and terminal infrastructure in place to meet the forecast growth in local and regional demand.

**Current pipeline structure**

The current pipeline structure is set out in the table below. It reflects the age and relative throughput capacities of each of the pipelines. Pipeline systems are built to last for approximately 25 years, but as they get older the level of corrosion and maintenance increases to a point at which they need replacement.

*Table 6.10: Current pipeline structure*

| | From | To | Length (km) | Diameter (inch) | Date installed | Installed low rate (m3/hr) | Working flow rates (m3/hr) | Pump Stations |
|---|---|---|---|---|---|---|---|---|
| **LINE 1** | Mombasa | Nairobi | 450 | 14 | 1978 | 880 | 607 | 9 |
| **LINE 2** | Nairobi | Burnt Forest | 282.8 | 8 | 1994 | 249 | 188 | 4 |
| | Burnt Forest | Eldoret | 47 | 6 | 1994 | 240 | 120 | |
| **LINE 3** | Sinendet | Kisumu | 125 | 6 | 1994 | 110 | 109 | 0 |
| **LINE 4** | Nairobi | Eldoret | 325.2 | 14 | 2008 | 370 | 340 | 2 |
| **Spur line** | KOSF | SOT | 2.8 | 12 | 2008 | 400 | | 0 |
| | KOSF | KPRL-SOT | 4 | 12 | 2008 | 200 | | 0 |

*Source: KPC*

Key issues:

- The current pipeline structure requires upgrading and expansion, not only to meet current demand but to deliver the projected four- fold increase in local demand.
- Transit demand is forecast to increase from 2 million $m^3$ per annum to 4 million $m^3$ per annum over the period on the assumption that the Uganda refinery is built in 2020 at 30 000bpd and expanded to 60 000bpd in 2025.
- The major pipeline (Line 1) from Mombasa to Nairobi is over 35 years old and its working flow rate, at approximately 610$m^3$/hour is well below its installed capacity rate of 880$m^3$/hour. The flow rate is also below the current pipeline demand for Nairobi and beyond which has resulted in increased road bridging particularly from Mombasa to Nairobi.
- The 6 inch spur line to Kisumu is insufficient to meet demand.
- The pipeline needs to be linked to all the key terminals both public and private.

### Supply Demand Model

In order to understand the pipeline supply capacity versus demand forecasts a planning model has been built to calculate the volume surplus or deficit by key location for the period to 2040. This has been used to test the results under different scenarios and has been used as a platform to consider both the planned pipeline upgrades and new terminal requirements.

### Planned Pipeline Upgrades

KPC are currently addressing the major short term pipeline requirements which are set out below and have been incorporated and reviewed against the supply demand model.

<u>Mombasa to Nairobi:</u>

- **Phase I**: The replacement of the existing Mombasa-Nairobi Pipeline with a 20" pipeline (Line 5) commenced in August 2014 costing approximately US$ 490m with a capacity of 880 $m^3$/hour. It is scheduled for operation in 2016, which will alleviate the current demand deficit.

- **Phase II**: This planned pipeline upgrade is scheduled to commence in 2023 and will involve adding an additional pump at four stations. Concurrently it will involve constructing 4 new pump stations with 3 booster pumps each (2 running continuously and 1 on standby) to give an installed flow rate of 1,830$m^3$/hr. Estimated cost (KPC) is US$ 140m.

- **Phase III**: A parallel pipeline (Line x) is scheduled for 2037 to meet the increased demand. The initial consideration was a 14" line but, following discussions, this is likely be a 20" line with an estimated cost (KPC) of US$ 777 m.

The precise timing of Phases II and III will need to be monitored against updated demand forecasts.

<u>Nairobi to Eldoret:</u>

Line 4 currently has one pump each at Nairobi and Nakuru and can operate at a flow rate of 378 $m^3$/hr. Phase 2 from 2019-2025 will have two pumps in Nairobi and Nakuru which will increase the flow rate to 531 $m^3$/hr. Phase 3 from 2026-2030 will have pumps in Ngema, Naivasha and Sinendet and will improve the flow rate to 757 $m^3$/hr.

<u>Sinendet to Kisumu:</u>

KPC proposes to lay a 10 inch pipeline measuring about 122km from Sinendet to Kisumu with an installed flow rate of 340$m^3$/hr. This pipeline will be operated in parallel to the existing 6 inch diameter pipeline (Line 3) and will tee-off from the existing 14 inch diameter Nairobi – Eldoret pipeline (Line 4) at Sinendet.

### Leak detection system and centralized communication

To achieve substantial improvements in efficiency and operation of the overall pipeline system a centralised system of control is envisaged. Provision of a new supervisory control and data acquisition system (SCADA) costing approximately US$ 25m, which is a sophisticated system that allows online remote control of the entire pipeline system including leak detection and flow rates is seen as an essential pre-requirement to deliver the centralisation.

### Summary of planned projects

The total estimated capex for the Kenya pipeline upgrades discussed above is US$ 1,625m of which US$ 490m is currently approved and in progress. Based on the supply demand modelling done this will meet the base case Kenya and transit demand for the Master planning period to 2040 as summarised in the table below.

*Table 6.11: Pipeline capacity plans and capital investment*

| | Line | inches | date | $m^3$/hr | Capex US$ millions | annual million $m^3$ |
|---|---|---|---|---|---|---|
| **Mombasa – Nairobi** | Line 1 | 14 | 2013 | 880 & 615 | - | 5.2 |
| | Line 5 | 20 | 2016 | 880 | 490 | 6.9 |
| | | upgrade | 2025 | 1,830 | 140 | 15.4 |
| | Line X | 14 - 20 | new 2040 | 1,200 | 777 | 10.1 |
| | | | | | **1,407** | **25.5** |
| **Nairobi –Eldoret** | Line 2 | 6 - 8 | 2013 | 220 | - | 1.8 |
| | Line 4 | 14 | 2013 | 378 | | 3.2 |
| | Line 4 | upgrade | 2019 | 531 | 25 | 4.5 |
| | Line 4 | upgrade | 2026 | 757 | 25 | 6.4 |
| | | | | | **50** | **6.4** |
| **Sinendet - Kisumu** | Line 3 | 6 | 0 | 110 | - | 0.9 |
| | **Line 6** | **10** | **2017** | **400** | **148** | **3.4** |
| | | | | - | **148** | **3.4** |
| **TOTAL** | | | | | **1,625** | |

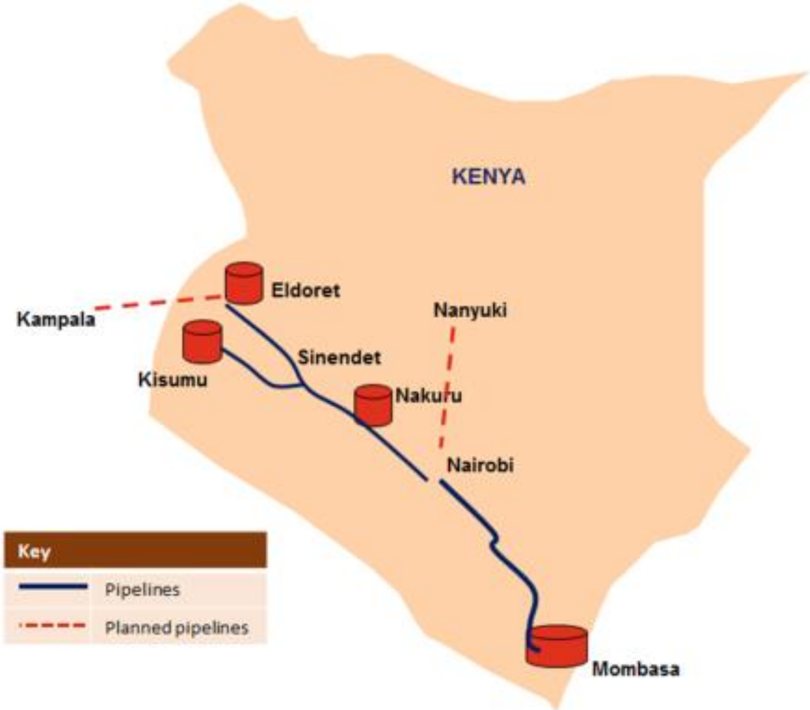
*Source: KPC*

### Potential branch lines and Export pipelines

The potential planned branch lines and export pipeline from Eldoret to Kampala and Kigali have been excluded from the costings in table above given the current uncertainty on timing and their development.

Branch lines - that are currently under consideration are either from Nairobi or Nakuru to Nanyuki to meet the Central region demand. Other branch lines will be considered but are likely to be driven off the back bone of the current pipeline routes.

*Figure 6.18: Current and future pipelines*




*Source: KPC*

Export pipelines - The Eldoret - Kampala pipeline and the extension thereof to Kigali has been on the drawing board for a number of years. It has been the subject of a number of proposals particularly since the discovery of crude oil in Uganda and the decision by the Ugandan Government to build a 30,000 b/d refinery with a potential to upgrade this to 60,000b/d.

The current status of the proposed pipeline according to KPC is:

*"The Government of the Republic of Kenya, the Government of the Republic of Uganda and the Government of the Republic of Rwanda resolved to cooperate in the development of the Eldoret-Kampala-Kigali Refined Petroleum Products Pipeline.*

*This project is being spearheaded by the three Heads of States through the Northern Corridor Integration Projects Summit. Financing of the project shall be by the three Governments.*

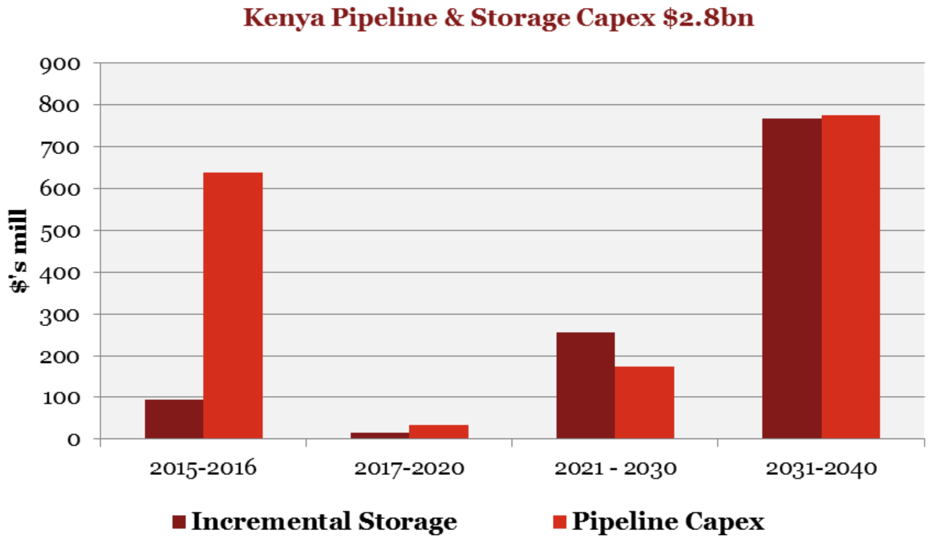
*KPC is part of the team providing technical advice on the project.*

*The three Governments engaged a consultant who prepared the tender documents for the Project.*

*An expression of interest was opened on 30th September 2014, eight (8) bidders were prequalified for the Engineering, Procurement and Construction contract. Issuance of Request for Proposals to the prequalified bidders is pending awaiting feedback on financing from the Ministers of Finance from the partner states."*

The estimated cost of the 352 km pipeline from Eldoret to Kampala is US$ 350m and the 525 km pipeline from Kampala to Kigali is US$ 518m.

*Figure 6.19: Pipeline and storage capital expenditure forecast*




*Source: PwC Consortium Analysis*

**Export pipeline Challenges**

There are a number of key challenges that need to be addressed in terms of prioritisation, risk and project economics before proceeding with the export pipeline:

- The Ugandan refinery is forecast to be onstream by 2020 and will produce approximately 1.25 million $m^3$ (30,000 b/d) of pipeline product which is approximately 80 % of Ugandan and Eastern DRC current demand, with the potential to upgrade to 2.5 million $m^3$ (60,000 b/d) which would meet Uganda's demand to approximately 2030.
- How does this export product pipeline rank in terms of priority relative to the other Kenya crude and oil projects?
- Is there a take or pay arrangement to minimise the risk for Kenya in building an export pipeline?

We would recommend that bilateral Government discussions are held to resolve these issues prior to any commitment to developing the export pipeline.

**Key storage and Pipeline Recommendations**

Plans are in place to meet the immediate pipeline deficits but a multi- functional team will need to prioritise and agree not only the pipeline priorities but the entire supply chain upgrade and developments as set out in 6.2.9 below.

### *6.2.9. LPG Infrastructure development*

According to the PIEA, one of the key issues for downstream oil is development of LPG facilities in Nairobi. The overall objective of developing the LPG facilities in the country is to ensure availability and accessibility of LPG at cost effective prices, promote the use of LPG as a household fuel among the urban and rural population and enhance socio-economic development.

A feasibility study under the auspices of KPC was completed in 2013 which underlined the limited supply chain and infrastructure for LPG in the country and recommended a proposed infrastructure facilities development plan to complement the upgraded AGOL terminal and import facility at Mombasa.

There are currently 3 licensed LPG storage facilities and bottling facilities in the country; Mombasa – 15,490 MT; Nairobi – 1,404 MT; and Eldoret - 100 MT. This is insufficient to meet current demand estimated at 91,600MT, and future demand. The study projected that if the supply constraints are removed, consumption by year 2035 would grow to about 333,759 MT under a 'Business as Usual' scenario and 735,217 MT under an 'Optimistic Business' scenario.

**Recommendations:**

The KPC study recommends construction of LPG facilities at Nairobi, Nakuru, Kisumu, Eldoret and Sagana. The table below provides a summary of the proposed storage capacities in Phase I and II and associated cost estimates with Phase I initially proposed for 2013 -2014 and the second phase in 2024 dependent on actual demand growth.

*Table 6.12: LPG proposed storage capacity and cost*

| Facility Location | Storage Capacity MT | | Phase I Capex - 2014 (US$ million) | Phase II Capex - 2024 (US$ million) | Total Project - Capex (US$ million) |
|---|---|---|---|---|---|
| | Phase I | Phase II | | | |
| Nairobi | 2,220 | 3,760 | 22.9 | 6.9 | 29.8 |
| Nakuru | 600 | 950 | 15.2 | 4.8 | 20.0 |
| Eldoret | 800 | 1200 | 14.3 | 4.5 | 18.8 |
| Kisumu | 800 | 1200 | 17.1 | 5.4 | 22.5 |
| Sagana | 800 | 1100 | 13.6 | 4.3 | 17.9 |
| **Total Project Cost** | | | **83.1** | **25.9** | **109.0** |

*Source: PIEA*

All facilities will have cylinder filling plants, tanker loading gantries and other auxiliary facilities. It is expected that initially all volumes will be handled by road until a new rail system is available.

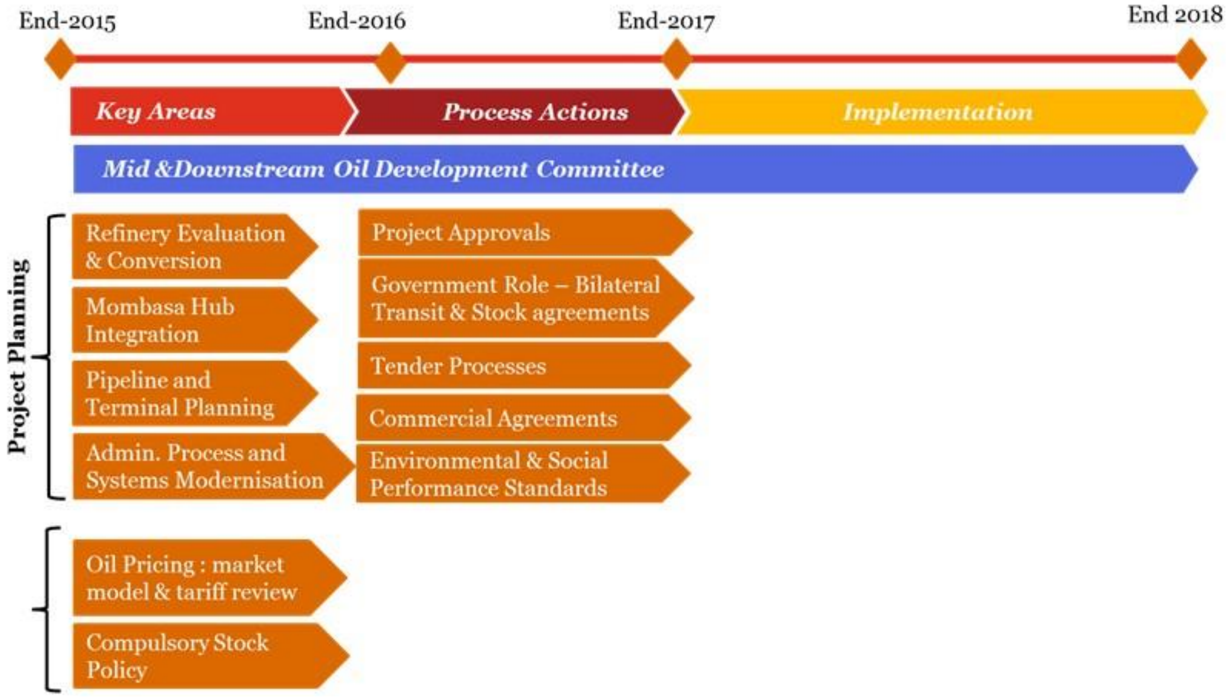
The financial and economic viability of the project has been included in the Study. The timing and prioritisation of the LPG phase I project, in particular the Nairobi LPG plant would need to be considered as a part of the overall prioritization process unless privately funded.

### *6.2.10. Conclusions and Recommendations*

The oil product infrastructure is an essential utility to underpin Kenya's commercial growth, the quality of life for its residents, and provides an important source of income for the Kenyan Government. Now aging and outmoded, the following key actions are recommended to provide an efficient infrastructure system for the Master Planning period ahead.

The key to moving forwards on oil infrastructure is to create alignment on the need for change, and belief in the Vision of a modern oil product infrastructure.

*Figure 6.20: Regenerating oil product infrastructure*




*Source: PwC Consortium*

Form the Downstream Oil Development Committee who will be responsible for managing the prioritisation of the projects, upgrading the facilities, development of efficient systems to manage product importation and distribution. This committee needs to incorporate the key stakeholders in the product supply chain. Specifically the following working groups need to be set up reporting to this committee:

- Refinery Working Group – with objectives to align the need for change and re-development. This work should be completed by end-2016.

- Mombasa oil hub integrated planning. This work also needs to start straight away, as the old oil facilities in the port are being relocated, and the port is preparing its own plans for replacement. These plans need to be integrated together. The working group should initially focus on port and storage integration issues, but may not be able to provide a consolidated detailed plan until end 2016.

- KPC should lead a pipeline and terminal network planning review to take account of proposals made in this Master Plan. The review should include:
    - Verification of pipeline capacity versus demand.
    - Whether a second larger capacity pipeline Mombasa/Nairobi is justified from 2035.
    - Confirmation of Uganda refinery and implications for the Eldoret to Kampala pipeline.
    - Distribution optimisation including bottom loading, gantry automation, 24 hour operation.
    - LPG development plan.

- Modernisation of the administrative processes and systems is a key step to streamline the flow of product along the oil supply chain from planned importation to final customer. It is anticipated that changes to organizational management, administrative processes, network computing, measurement and control systems will all be required to achieve leading 21st century performance.

- Oil Pricing- Market based pricing and pipeline tariff review. To be led by ERC.

- The Compulsory Stock Policy. This should be started immediately. Although no consequent on the refinery future, it will provide redevelopment opportunities which are seen as key to acceptance of the need for change. This work should also be completed by end 2016.

Coordination of the scope of activity, costs and timeline for each project will need to be reviewed by the Downstream Oil Development Committee by end 2016.

# *Gas Sector*

# 7. Gas Sector

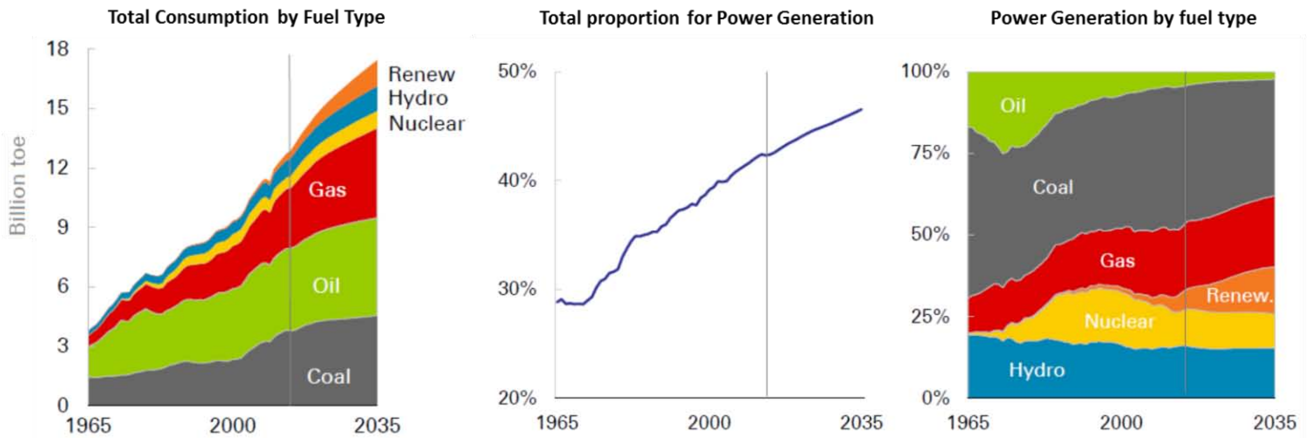
## 7.1. Setting the scene

### 7.1.1. Global gas demand

Before discussing detailed gas supply and demand options for Kenya through this Chapter, we provide a general background to global gas consumption, trade and gas monetisation options below. Gas consumption has increased significantly over the last few decades and given its cleaner and more efficient burning properties is expected to play a major role in meeting overall energy demand in many countries.

According to 2015 BP Energy Outlook, total global energy consumption will have increased from around 8.1 Billion tonnes of oil equivalent (toe) in 1990 to just over 13 Bn toe by 2015. Over this period, gas consumption as part of total global energy consumption will have increased from 22% to 24% (in comparison to coal (from 27% to 29%) and oil (from 39% to 32%)), and is expected to continue to increase to account for 26% of the 17.5 Bn toe of total energy expected to be consumed globally by 2035 with oil (29%), coal (26%), renewables (7%), hydro (7%) and nuclear (5%) making up the remaining share. In terms of power generation, gas' share as a fuel in the global power generation mix is expected to have increased from 17% of 2.9Bn toe in 1990 to 21% of 5.6Bn toe by 2015 and 22% of 8.1 Bn toe by 2035. Despite its share in the power generation mix falling from 40% to 36% over the same period, coal is expected to remain the dominant fuel in power generation. The share of nuclear and hydro in the power generation mix is expected to remain approximately the same at around 10% and 15% respectively out to 2035, whilst the share from renewables is expected to increase from 1% to 14%.

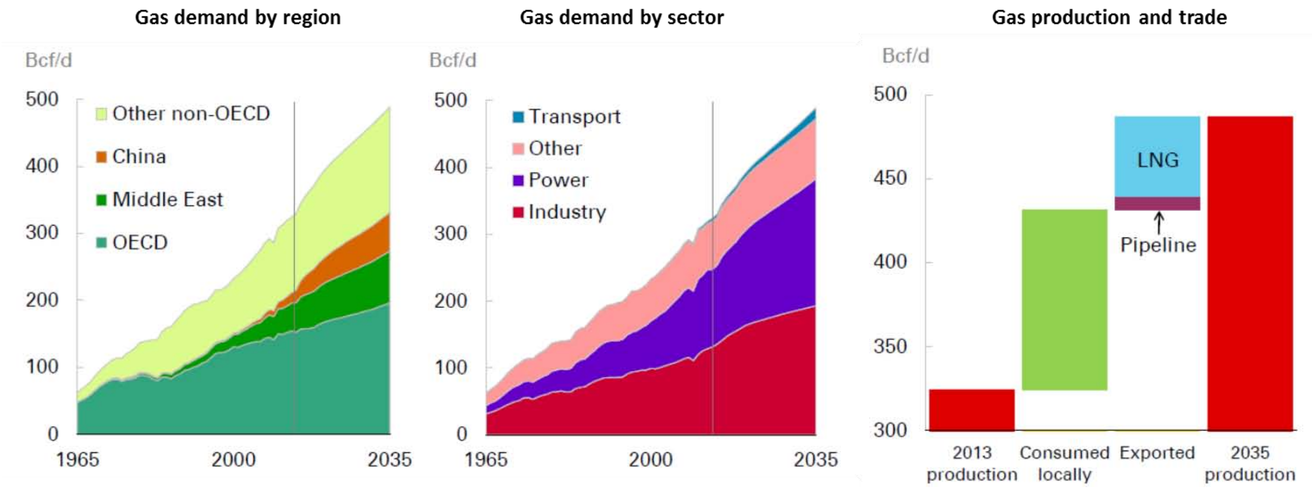
*Figure 7.1: Gas' share in total global energy consumption*




*Source: BP Energy Outlook 2015*

Total global gas consumption has increased considerably from 1.8Bn toe (190 Billion cubic feet per day (Bcf/d)) in 1990 to 3.2Bn toe (345 Bcf/d) by 2015 and expected to exceed 4.5Bn toe (490 Bcf/d) by 2035. The share of gas consumption for power generation has increased from 28% in 1990 to 36% in 2015 and in industry has dropped from 45% to 40% over the same period. The share of gas consumption in power generation and in industry is expected to continue this trend and account for 40% each by 2035, whilst the share of gas consumption in transport is expected to increase from current levels of around 1.7% to 3.5% of total gas consumption. The remaining share of gas use is from the residential & commercial sector (shown as 'Other' in the figure below), which has dropped from 27% in 1990 to around 21% and expected to continue to drop further mainly due to further electrification and increased efficiency of gas use in this sector.

*Figure 7.2: Global gas consumption and trade*




*Source: BP Energy Outlook 2015*

In terms of international trade, gas exports currently make up around 30% of total gas consumption of which 21% is by pipeline and 10% as LNG. By 2035, according to BP estimates, growth in international gas trade is expected to make up around one third of the increase in total gas consumption – of which close to 90% of the increase will be through LNG supply. This will mean that international pipeline and LNG supply will represent just over 15% each of total gas consumption of 490 Bcf/d.

## 7.1.2. Potential for gas in Kenya

Demand for natural gas in Kenya is currently very low, if not zero, given the lack of indigenous or imported gas supply. However, as discussed in Chapter 4 (Upstream Oil & Gas Sector) with the recent discoveries of gas resources, Kenya can now at least consider the development of a local gas industry. In the Base Case total gas resource across the country is currently estimated to be around 11 Trillion cubic feet (Tcf) with the majority of this (8 Tcf) in the Coastal Lamu area and the rest offshore Mombasa (1.2 Tcf) and in North Kenya (1.6 Tcf).

As discussed above, gas is used as feedstock or for process heating in industry, for power generation, for space heating and cooking in residential and commercial sectors and to a lesser extent in road transportation. In terms of gas monetisation, options are generally for power generation, gas processing and export as LNG or pipeline gas, and production of gas products (mainly ammonia, methanol and petroleum products (Gas to Liquids)) for consumption locally or for export.

In determining options for gas monetisation and planning gas use locally several factors need to be considered. On the supply side this includes the size and location of gas resource and cost of production. On the demand side this includes current or expected gas demand in the different sectors, regulation, market prices and the development of infrastructure to deliver gas to the market.

In terms of local use, in countries with new gas markets it is important to initially base the development of the market on large scale 'anchor' or base load projects, mainly gas fired power plants. With the cost of developing the main supply chain being largely borne by large anchor projects, other demand segments can then develop alongside major pipeline routings or adjacent to large anchor projects. Large anchor projects may also include methanol and fertiliser production plants, but would be limited by demand in local, regional and even international markets. While there is sufficient demand for petroleum products from Gas to Liquids (GTL) plants, GTL projects are costly and technologically very complex and have only been developed in a few countries as large scale export-focused options. Below we provide some high level indications on the general characteristics, costs and economics of typical local projects before describing them in more detail through the report.

| | Production | | Gas Requirement | | Cost | | Economics | |
|---|---|---|---|---|---|---|---|---|
| **Option** | **Scale** | **Output** | **Supply (MMScfd)** | **Reserves (Tcf)** | **Capital $m** | **Opex $m/yr** | **Product price** | **Netback^ $/MMBtu** |
| Gas fired Power Generation * | 800MW | 4,200 GWh/yr | 75 | 0.73 | 875 | 35 | $100 /MWh | ~10 |
| Ammonia/Methanol production ** | 1 mtpa | 3,000 t/day | 80 | 0.84 | 1,000 | 50 | $350/t | ~4 |
| Large scale industrial park *** | - | - | 15 | 0.16 | - | - | $800/t | ~10 |
| * Assumes 60% load factor, 55% thermal efficiency, 30 year project lifetime | | | | | | | | |
| ** 28 MMBtu gas to produce 1 tonne, 30 year project lifetime | | | | | | | | |
| *** Output and costs are non standard and depend on product manufactured, price based on average of HSFO and Gasol as alternatives (DES Mombasa excl taxes) | | | | | | | | |
| ^ Netback estimates are indicative and are based on the Base Case assumptions in the Gas Modelling Section | | | | | | | | |

*Source: PwC Consortium Analysis*

As shown above, gas products projects typically require cheap indigenous sources of gas (with a delivered cost of no more than $4/MMBtu to the plant), unlike gas use in power generation and in industry where netbacks are much higher given higher product prices based on alternative fuels which are more expensive. There is however good potential to develop a large gas local industry in Kenya driven by gas use in power generation. Based on current resource estimates, if this was all used for power generation, there would be enough gas to develop over 12GW of new power generation. As discussed below, this is much above current and expected power demand levels, but there may also be significant demand from the industrial sector if supply infrastructure is developed as is the case in many developed gas markets.

In terms of exports, given the sharp rise in LNG plant development costs over the last decade (mainly due to high costs for materials and shortages of skilled labour), LNG export projects have had to be based on at least two liquefaction trains in order to benefit from economies in scale requiring a minimum of 13 Tcf of gas reserves. However, total estimated gas resources in Kenya is currently estimated at 11 Tcf, of which only 8 Tcf is in Coastal Lamu, which is below the 13 Tcf required to justify the development of a minimum two train LNG export project. Hence, we assume that no LNG export project would be developed in the Base Case. For comparison, the LNG projects in Tanzania and Mozambique – albeit likely to be three train projects – are based on gas reserves of around 50 Tcf and 100 Tcf, respectively. In the High Case for Supply Potential in Kenya, with resources estimated to be around 30 Tcf in total, 24 Tcf of which is expected to be located in the Coastal Lamu basin, there could be sufficient supply available to justify a two or maybe a three-train LNG project. However, this High Case is heavily conditional upon continued investment in upstream exploration and production.

In terms of pipeline exports to neighbouring countries, the proximity of large gas discoveries in Tanzania and Mozambique means that potential exports would be limited to markets to the West (Uganda) and North (Ethiopia, South Sudan) of Kenya, where demand is likely to be less than in Kenya and may not high enough to justify the transportation costs of a long distance gas pipeline. Hence, in both the Base and High Cases we assume pipeline exports will not be realised. As shown below, even world scale GTL plants would struggle to make sufficient returns given high capital costs and large fuel consumption in comparison to LNG production. Netbacks of around $3/MMBtu is below expected gas production costs and therefore uneconomical.

| | Production | | Gas Requirement | | Cost | | Economics | |
|---|---|---|---|---|---|---|---|---|
| **Option** | **Scale** | **Output** | **Supply (MMScfd)** | **Reserves (Tcf)** | **Capital $m** | **Opex $m/yr** | **Product price** | **Netback ^ $/MMBtu** |
| LNG production * | 8 mtpa | 410 TBtu per year | 1,250 | 13.1 | 11,200 | 500 | $12/MMBtu | ~6 |
| Long distance pipeline ** | 5 Bcm/yr | 190 TBtu per year | 504 | 5.3 | 2,000 | 80 | $10/MMBtu | ~8 |
| Gas to Liquids *** | 50k bbl/day | 100 TBtu per year | 450 | 4.7 | 5,000 | 250 | $800/t | ~3 |
| * Assumes 10% fuel consumption, 2x4mtpa trains, 30 year project lifetime | | | | | | | | |
| ** Assumes 1000km pipeline to Ethiopia or Uganda, 30 year project lifetime, Product price is assumed to be the netback for power generation | | | | | | | | |
| *** Assumes 40% fuel consumption, 30 year project lifetime | | | | | | | | |
| ^ Netback estimates are indicative and are based on the Base Case assumptions in the Gas Modelling Section | | | | | | | | |

*Source: PwC Consortium Analysis*

It should be noted that netback estimates provided here are only high level indications on scale, gas requirements and economics of different gas monetisation options. Gas monetisation options for Kenya are discussed in more detail through this section and economic modelling is discussed in more detail in section 7.4.

### *7.1.3. Structure of Gas Section of Report*

Given the limited potential for gas exports from Kenya based on current estimates and location of gas resources, the focus of our report will be on developing the local gas market and mainly gas-fired power generation. In the next section we discuss potential gas demand for power generation in Kenya taking into account other forms of generation currently in place and planned in the short to medium term. We also discuss gas demand in the industrial, commercial, household and transport sectors as well as for ammonia, methanol and GTL production.

In the following section we provide an overview of the market, commercial, and technical aspects of 1) Gas-fired power generation projects 2) Ammonia projects, 3) Methanol projects, 4) Gas use in the industrial sector and 5) LNG export projects. We discuss and estimate plant and supporting infrastructure capex and opex and how these have evolved more recently. We provide an overview of the types of players involved along the chain and options for GoK and National Oil Company's (NOC) participation, giving examples from other projects around the world. This section is a standalone section which aims to provide a detailed understanding of individual project options.

In the final section, we discuss strategic considerations for the start-up and development of the natural gas industry in Kenya. Given that indigenous production is still a number of years away, we discuss the role, costs and benefits that imports through the development an LNG import project could play in kick-starting the industry and the potential replacement of LNG imports with indigenous gas supply as this becomes available. We also describe strategic considerations for gas project siting and requirements for gas infrastructure across Kenya taking into account gas supply and demand locations under different gas supply growth scenarios. In conclusion, we outline the critical success factors and commercialization challenges for the successful development of the Kenyan natural gas sector.

## 7.2. Gas Demand

### 7.2.1. Introduction

In this section we consider the different options for consuming gas and gas products in Kenya and estimate the level of gas demand in the local power generation, industrial, commercial & residential and transport sectors. In terms of gas demand as feedstock in the production of ammonia, methanol and gas to liquids (GTL), we consider this from the perspective of both local and export options. With LNG being an export option we discuss this in detail in the next section.

In common with many other countries around the world, the early development of a local gas industry in Kenya is likely to be primarily based on gas use in power generation. We consider the role for gas-fired power generation in the medium-longer term (from 2020 to 2040) as this is the period when indigenous gas supply is most likely to be available. We take into account findings and build scenarios around the Least Cost Power Development Plan undertaken by the Energy Regulatory Commission and key players in the Kenya power sector. However, we also recognize that there are particular challenges with power generation capacity planning and comment on this in light of the opportunities for gas use in power generation. We do not, however, create a wider Power Sector Master Plan as this is not the objective of this Study.

In the next section (Gas Monetisation Options, Infrastructure and Operational Requirements) we provide more detail on the market, physical, technical and cost aspects of more likely monetisation options for Kenya.

### 7.2.2. Gas demand in power generation

#### 7.2.2.1. Background

Approximately 98% of power generation capacity in Kenya as at 30 June 2014 consisted of hydro, geothermal and heavy oil-fired power generation, with wind, solar, and biomass making up the rest. Up until two years ago, hydro made up more than 50% of power generation capacity before geothermal projects started to come online. In terms of location, a large majority of the hydro power generation plants are located some 100-150km North East of Nairobi along the Tana River. The majority of the oil-fired power generation plants (mainly fuel oil) are located in Mombasa (359MW – Kipevu I, III, Tsavo and Rabai), and two plants are located in Nairobi (60MW – Embakasi Gas Turbines, 108.5MW – Iberafrica). All geothermal power generation is located at Olkaria near Naivasha, some 70km North West of Nairobi. In terms of demand, Nairobi accounts for close to 56% of total power consumption, with around 19% in Mombasa, 17% in the cities in the Western region and 8% in cities around Mt Kenya (2013/4 official figures).

Kenya is in a unique position. With one of the fastest growing economies in Africa, demand for power is rapidly increasing, albeit from a low base. The high reliance on seasonal hydro power generation has at times led to shortages, and along with costly oil-fired power generation and poor transmission, risk slowing growth in the economy. Over the last few years the Government has been addressing this issue as a matter of priority.

In September 2013, the MoEP launched a plan to bring 5,000+ MW of new power generation capacity online within forty months (by 2017), adding to the currently installed 1,885MW of power (30 June 2014). The plan consisted of the addition of 1,646MW from geothermal sources, 1,920MW from coal-fired power plants, 24MW from hydro, 630MW from wind and 1,050MW from gas-fired power plants and 250MW from oil-fired power plants.

Based on information provided by KPLC, which is responsible for all power transmission and distribution in Kenya, in 2014 326MW of geothermal, 197MW of oil-fired and 32MW of hydro power generation came online. With demand now lagging behind, at the time of writing, Kenya is in a position of power generation capacity oversupply and delays to the 5,000+MW plan are expected. More realistic views of the 5,000+MW plan developed in conjunction with KPLC for this study assume that between 2015 and the end of 2020, significant new power generation capacity is still expected to come online from geothermal (932MW), coal (2,302MW), wind (711MW) and hydro (437MW). The addition of 5,000+MW is now expected to be met in 2020, and even then further delays may occur if demand is still lagging.

The risks and implications of power generation capacity overbuild are not considered in this Study but are important to consider as part of a detailed Power Sector Master Plan. It will be key for the Government to ensure that projects are only brought online in line with demand and that investment is also made in power transmission and distribution. Despite risks of capacity oversupply, other than geothermal power, what is lacking in Kenya is a reliable form of baseload power generation. This can only be provided on a reliable basis by thermal or nuclear power generation. Developing a nuclear power plant has many challenges and requires considerable upfront investment. Thermal fired power generation is simpler to develop and gas is the preferred form given its efficiency and better environmental impact properties compared to coal and oil. This is considered in more detail below.

In terms of coal, the Government has planned the development of two large (1,000MW) coal-fired power plants – one based in Lamu (which has been awarded but still negotiating terms with the bidder) and another adjacent to the large prospective domestic coal reserves near Kitui (150km East of Nairobi). Both are still currently planned to come online before the end of 2020.

In terms of gas, the Government initiated the planned joint development of a Floating Storage and Regasification Unit (FSRU)-based LNG import terminal and the adjacent 700MW gas-fired power plant in Dongo-Kundu, Mombasa. LNG supply was also expected to re-fire 285MW of existing oil-fired power generation in Mombasa. This was originally planned to be online in 2017, however with the recent cancellation of the existing international tender due to non-conforming bids by shortlisted developers, this project will no longer be able to meet the intended date. It is still unknown if and when the Government will re-tender for this project. No other gas-fired power generation projects are considered, mainly because Kenya has only recently understood the potential it has for indigenous gas supply and is evaluating the implications.

In this Study, we discuss how the LNG to power project can still play an important part in kick-starting the development of the gas to power industry in Kenya and, due to the ability to redeploy FSRU-based assets used for LNG import, providing upstream producers more certainty on investing in production by establishing an outlet for their gas. However, in light of the capacity oversupply risks as discussed above, we assume that if an LNG to power project were to be developed then it would come online post-2020 and approximately 5 years before significant amounts of indigenous gas production is expected to commence. Nevertheless, there is still a strong case for developing the LNG to power project in preference to the planned import-based coal-fired power project before 2020, as discussed in more detail in our recommendations later in this section.

Below we develop some scenarios to provide an indication on the role that gas-fired power generation can have in Kenya using potential indigenous gas reserves assumed to be available post-2020.

## *7.2.2.2. Gas demand for power generation projections*

### *7.2.2.2.1. Overview of methodology*

In terms of developing scenarios for gas demand in power generation, we have assumed in our Base Case that gas-fired power generation only gets developed once indigenous supply can potentially come online post-2020. Hence, our main focus is on the medium-long term (out to 2040). We nevertheless consider the impact of delays to the 5000+MW plan (see below) on overall power demand going forward. We also comment on how gas-fired power generation is likely to be more advantageous than the other forms of power generation being considered as part of the plan.

In considering the role for gas-fired power generation in the medium-long term, we have used the 2011 LCPDP study (as the 2013 update is not yet officially published and an update for 2015 is due soon) to create scenarios to consider the gap that gas-fired generation can have to fill if other forms of generation are not realized or realized to a lesser extent. In the short-medium term (up until 2020), rather than the LCPDP 2011, we have used the latest views from KPLC on timing for when planned power projects may potentially come online.

It should be stressed that, although we form views on what seems more or less likely at a high level, assumptions for medium and long term projections are only made to consider the potential gas demand, i.e. there is no reason to change assumptions made in the (revised) LCPDP other than to consider alternatives around how much gas-fired power generation may be required to meet the Governments medium and long term targets for total installed power generation capacity.

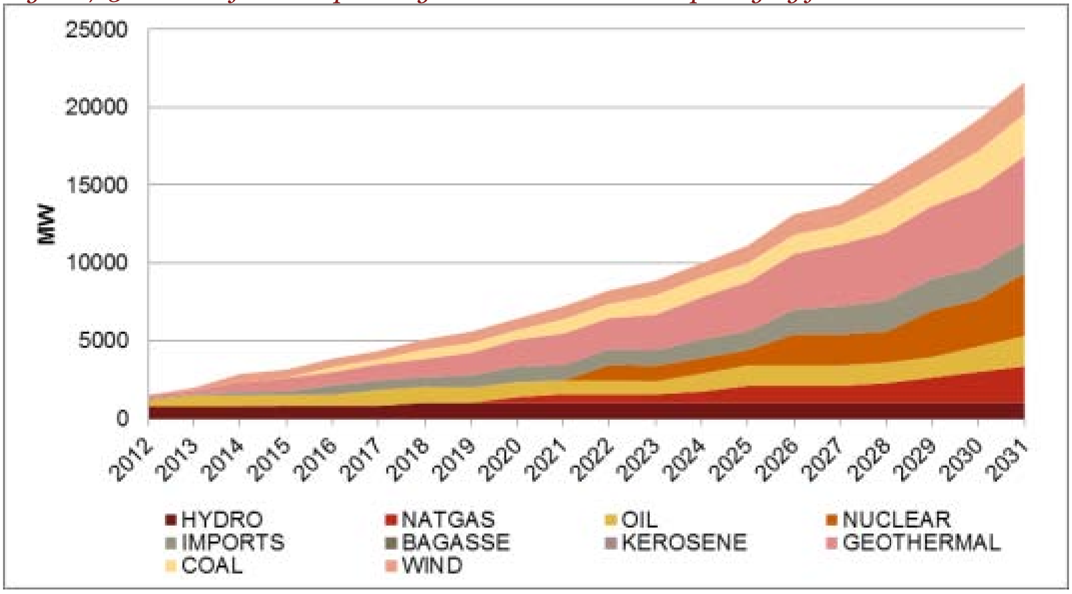
It should also be stressed that in the short term up until 2020, views on planned power generation are not critical for the purposes of this Study. We only provide this in order to give a high level view on all options for power generation being considered in Kenya and overall power demand and how they relate to the development of gas-fired power generation and the kind of gas volumes that would be required for further consideration.

### *7.2.2.2.2. Least Cost Power Development Plan (LCPDP) 2011 power generation projections*

The Energy Regulatory Commission's latest LCPDP published in March 2011 is shown below[20]. It should be noted that an update of this plan for 2013 has been produced as a draft but is not officially published. It should also be noted that neither study includes plans for the 5,000+MW plan currently being targeted by the Government. Hence, we have updated the 2011 LCPDP projections out to 2020 to incorporate the 5000+MW plan, using more realistic views on timing for planned power projects from the PwC Consortium's analysis.

According to the LCPDP 2011 projections, total power demand is projected to exceed 19,000MW by 2030 – a CAGR of 16%. This is based on strong year on year economic growth rates, and hence may seem overly optimistic in comparison to economic growth rates of less than 10%, and particularly from the current 1,885MW. The Kenyan Government has through its Vision 2030 stated a long term target to increase total power generation capacity to 15,000MW by 2030 – a CAGR of 14%. This is also likely to be overly optimistic and given the recent oversupply concerns we assume the 15,000MW target for total power generation capacity is met post-2040 rather than by 2030 – representing a CAGR of below 8% and more consistent with actual growth rates in power demand of 6.5% observed over the last 5 years (2010-2014). We use the total power generation projections and medium-long term views from the LCPDP 2011 to developing scenarios for gas-fired power generation.

*Figure 7.3: LCPDP forecast power generation installed capacity by fuel*




*Source: LCPDP March 2011*

*Table 7.1: LCPDP power generation capacity projections*

| MW | Hydro | Natgas | Oil | Nuclear | Imports | Bagasse | Kerosene | Geothermal | Coal | Wind | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2015** | 839 | 0 | 705 | 0 | 200 | 26 | 0 | 843 | 20 | 535 | **3,168** |
| **2020** | 1,039 | 360 | 969 | 0 | 1,000 | 0 | 0 | 1,728 | 620 | 735 | **6,451** |
| **2025** | 1,039 | 1,080 | 1,315 | 1,000 | 1,200 | 0 | 0 | 3,128 | 1,220 | 1,136 | **11,118** |
| **2030** | 1,039 | 1,980 | 1,635 | 3,000 | 2,000 | 0 | 0 | 5,110 | 2,420 | 2,036 | **19,220** |

*Source: LCPDP March 2011*

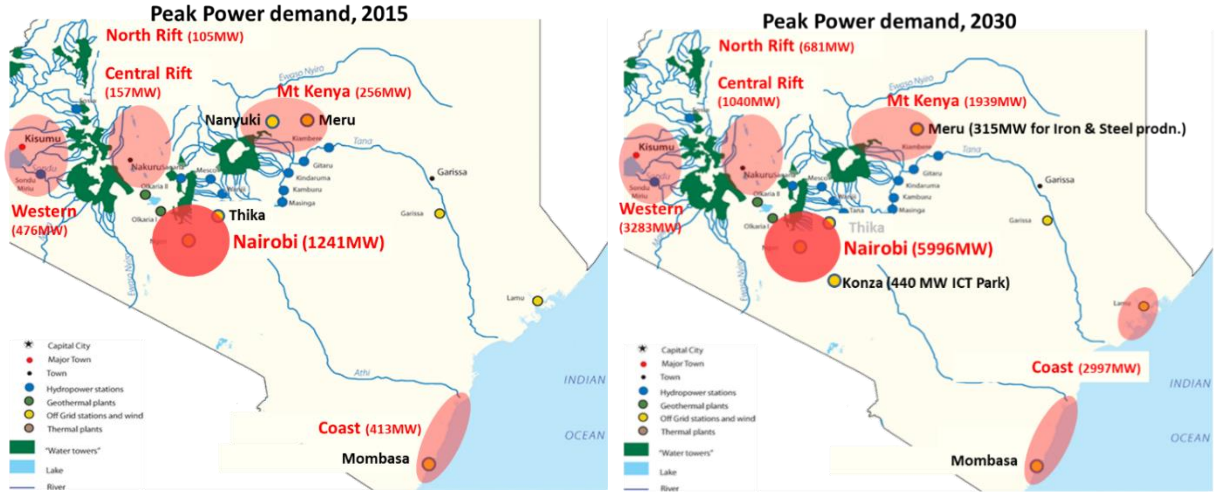
[20] To prepare the LCPDP, ERC set up a multi-stakeholder committee to undertake this task on an annual basis. The stakeholder committee includes representatives from the following key players: the Ministry of Energy (MoE), Ministry of State for Planning, National Development and Vision 2030, Kenya Electricity Generating Company (KenGen), Kenya Power and Lighting Company (KPLC), Geothermal Development Company (GDC), Rural Electrification Authority (REA), Kenya Electricity Transmission Company Limited (KETRACO), Kenya National Bureau of Statistics (KNBS), Kenya investment Authority(KenInvest), and the Kenya Private Sector Alliance(KEPSA) .

The LCPDP 2011 assumes significant growth in geothermal power generation reaching 5,000MW by 2030. This target has also been stated by the Kenyan Government. 3,000MW of new nuclear capacity is also projected to come online from 2022 (1,000MW initially) and around 2,400MW of new coal-fired and 2,000MW of new gas-fired power generation is assumed to come online from 2017 and 2020 respectively. Imports of power and power generation from oil and wind are assumed to grow, but to a lesser extent than coal and gas. Little growth is projected for hydro power generation.

2,000MW of new gas-fired power generation capacity would require around 2 billion cubic metres (Bcm) of gas supply per annum if operating at baseload. If operating as peaking capacity, as is assumed in the LCPDP, gas demand would be much lower. In this Study we assume that this will not be the case. We assume that any new gas-fired power generation would have to operate at baseload to underpin the significant investment and to meet rapidly growing power demand.

LCPDP peak load power demand growth forecasts by key region are shown in the figure below. Peak load demand is assumed to increase from 2,386 MW in 2015 to 14,273MW in 2030. Though this may be overestimated, it still provides an indication of where major growth in power demand is expected around the country.

*Figure 7.4: Power demand forecast by region*




*Source: PwC Consortium Analysis, LCPDP 2011*

Around 40% of the growth in peak power demand is assumed to be in and around the Nairobi area. The Coastal region is expected to contribute around 20% of total demand growth. With geothermal, hydro and wind power plants being inflexible on location, it will be important to consider the siting of other new power plants, weighing up the costs and benefits of long distance power transmission compared to transporting fuel to power plants closer to demand centres. We discuss this in more detail in the Strategic Alternatives section.

The scenarios around gas' potential role in the overall power generation and the implications on gas supply requirements are discussed below.

### *7.2.2.2.3. Base Case Gas demand for power generation*

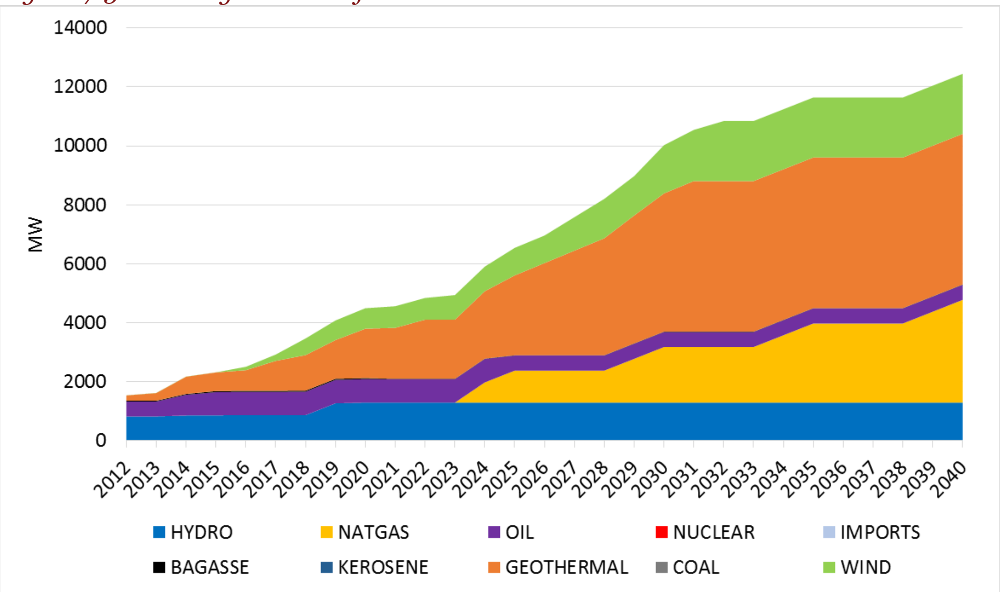
In the Base Case we assume all hydro, wind, oil-fired, and geothermal projects that are currently expected to come online in our delayed 5000+MW plan view are realised taking power generation capacity from 1,885MW to just under 4,500MW by 2020. This includes the addition of 437MW of hydro, 1,087MW of geothermal and 690MW of wind power generation. We also assume the planned development of two coal-fired power plants with combined capacity of 2,300MW before 2020 does *not* occur as; 1) despite providing reliable baseload supply, they may not be required from a demand perspective, and 2) gas-fired power generation is likely to be a better option for the reasons discussed below.

Post-2020, our assumptions are listed and shown in the figure below:

- Hydro: We assume no more hydro power generation is developed following the 437MW expected to be brought online before 2020.

- Oil-fired: Oil-fired power plants based in Mombasa (285MW) are converted to run on gas, leaving around 500MW (which has been added recently in the last 7 years) for consideration to be switched to gas if and when a gas supply network is developed in Kenya. No further oil-fired power plants are developed. This is much less than the 1,635MW by 2030 assumed in the LCPDP 2011.
- Imports: We assume no major power imports projects are developed. This is less than the 1,600MW of imports by 2025 and 2,000MW by 2030 assumed in the LCPDP.
- Wind: We have used assumptions made in the LCPDP albeit with a 2-3 year delay to reflect delays to current plans– steadily increasing to reach approximately 2,000MW by 2033.
- Geothermal: We have largely used assumptions made in the LCPDP with total capacity increasing from 1,674MW in 2020 (as currently expected) to just over 5,000MW by 2030. A target of 5,000MW by 2030 has also been expressed by the Kenyan Government. However, there are concerns that this may be overly optimistic, particularly as total global geothermal capacity is currently only 12,000MW.
- Coal: We assume no coal fired power generation is developed. With good potential for indigenous gas resources, gas-fired power generation is likely to be cheaper than import-based coal-fired power generation as well as being cleaner and more efficient. This is evaluated in more detail below.
- Nuclear: We assume no nuclear power generation is realised before 2040 due to the significant challenges of developing and financing such projects.
- Gas: We assume 1,085MW of gas-fired power generation based on indigenous resources is developed around 2025, including switching 285MW of oil-fired plant. This can be developed sooner depending on when indigenous production comes online. There is also a case to develop the initial plants even earlier based on LNG imports for a number of years before switching to indigenous as supply comes online, although timing will ultimately be dependent on demand. A further 800MW is assumed to be developed in each of the periods around 2030, 2035 and 2040, bringing total gas-fired power generation capacity to 1,885MW by 2030, 2,685MW by 2035 and 3,485MW by 2040.

*Figure 7.5: Power generation forecast – Base Case*




*Source: PwC Consortium Analysis*

*Table 7.2: Power generation forecasts - Base case*

| MW | Hydro | Gas | Oil | Nuclear | Imports | Bagasse | Kerosene | Geothermal | Coal | Wind | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2015** | 860 | 0 | 786 | 0 | 0 | 36 | 0 | 632 | 0 | 5 | **2,320** |
| **2016** | 867 | 0 | 786 | 0 | 0 | 36 | 0 | 702 | 0 | 115 | **2,507** |
| **2017** | 867 | 0 | 786 | 0 | 0 | 36 | 0 | 1,019 | 0 | 215 | **2,924** |
| **2018** | 867 | 0 | 796 | 0 | 0 | 36 | 0 | 1,204 | 0 | 565 | **3,469** |
| **2019** | 1,267 | 0 | 796 | 0 | 0 | 36 | 0 | 1,314 | 0 | 665 | **4,079** |
| **2020** | 1,292 | 0 | 796 | 0 | 0 | 36 | 0 | 1,674 | 0 | 695 | **4,494** |
| **2025** | 1,292 | 1,085 | 511 | 0 | 0 | 10 | 0 | 2,708 | 0 | 935 | **6,541** |
| **2030** | 1,292 | 1,885 | 511 | 0 | 0 | 10 | 0 | 4,690 | 0 | 1,636 | **10,024** |
| **2035** | 1,292 | 2,685 | 511 | 0 | 0 | 10 | 0 | 5,110 | 0 | 2,036 | **11,644** |
| **2040** | 1,292 | 3,485 | 511 | 0 | 0 | 10 | 0 | 5,110 | 0 | 2,036 | **12,444** |

*Source: PwC Consortium*

Assuming a load factor of 60% and a thermal efficiency of 55%, gas requirements in the Base Case would be approximately 1 Bcm/yr in 2025, rising to 1.8 Bcm/yr in 2030, 2.6 Bcm/yr in 2035 and to 3.3 Bcm/yr in 2040.

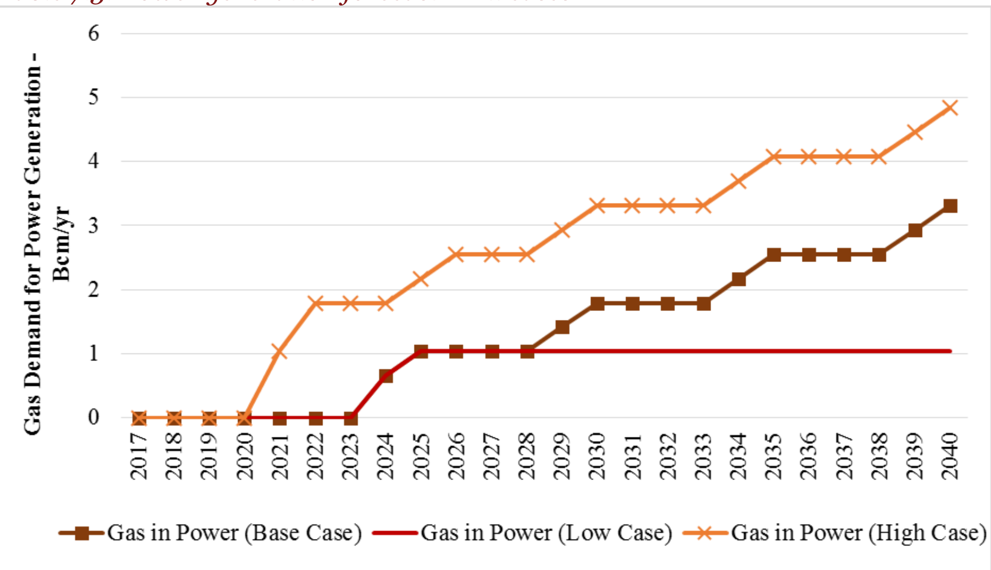
The High and Low Cases are derived in a similar way, with different assumptions on planned generation capacity that may or may not come forward.

In the High Case we assume 1,885MW of gas-fired power generation is developed earlier than in the Base Case around 2021-2022, including switching 285MW from being oil-fired, and is initially based on LNG imports. A further 800MW is assumed to be developed in each of the periods around 2025, 2030, 2035 and 2040, bringing total gas-fired power generation capacity to 3,885MW by 2030 and 5,485MW by 2040. LNG imports are assumed to be replaced by indigenous gas supply by the time additional power plants are developed around 2025. Assuming a load factor of 60% and a thermal efficiency of 55%, gas requirements in the High Case would be approximately 1.8 Bcm/yr in 2022, rising to 2.2 Bcm/yr in 2025, 3.3 Bcm/yr in 2030, 4.1 Bcm/yr in 2035 and 4.8 Bcm/yr in 2040.

In the Low Case we assume 1,085MW of gas-fired power generation based on indigenous resources is developed around 2025, including switching 285MW from being oil-fired. We assume no further gas-fired power generation is developed post-2025. Assuming a load factor of 60% and a thermal efficiency of 55%, gas requirements in the Low Case would be flat at approximately 1 Bcm/yr in 2025 through to 2040.

More detailed assumptions on the High and Low Cases are provided in the Appendix H.

*Table 7.3: Power generation forecast – All cases*

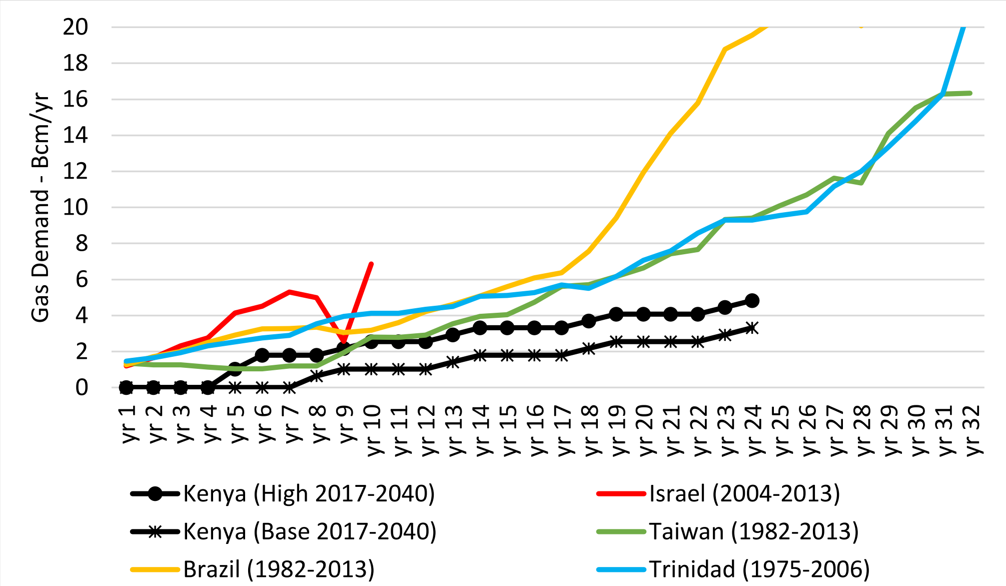


*Source: PwC Consortium Analysis*

### *7.2.2.3. Gas demand for power generation comparison*

The Base and High Case gas demand for power generation projections are compared below to historical total gas demand (though mainly power generation) in Brazil, Israel, Taiwan and Trinidad. All these markets have grown their domestic gas industries rapidly and from low bases.

*Figure 7.6: Gas demand for power generation - Base/High case international comparisons*




*Source: PwC Consortium Analysis*

Demand in Brazil rapidly increased through pipeline imports from Bolivia which started in 1999. It was not until 2008 and 2009 when Brazil developed FSRU-based LNG import terminals (with a total capacity of around 5 Bcm/yr) to supplement pipeline imports (10 Bcm/yr) and indigenous production that gas demand really accelerated. Brazilian indigenous gas production grew from around 3 Bcm/yr in the early 1990s to over 7Bcm/yr by 2000, to 14 Bcm/yr in 2008. Indigenous production is currently at around 20 Bcm/yr.

Trinidad is a major exporter of LNG and to a lesser extent Ammonia and Methanol. It had already started producing significant amounts (>10 Bcm/yr) of gas supply (given a population of around 1 million at the time) by the time LNG export projects started up between 1999 and 2006 (years 25 to 32 in the chart above).

Demand growth in Taiwan was initially based on small amounts of indigenous production until it developed its first LNG import terminal in 1990 (yr 9 in the chart above). With no options for pipeline imports, imports of LNG increased rapidly to meet demand for power generation. After several expansions of the existing terminal, a second terminal was constructed in the North of the Island.

With little indigenous production at the time, gas demand in Israel was developed through one indigenous offshore field development in 2003 followed by pipeline imports from Egypt which started in 2005. Demand was largely for power generation. Despite the pipeline system having capacity to deliver 10 Bcm/yr, actual gas supply was much lower than this. In March 2012 (Yr 9 in the chart), following a series of attacks on the pipeline between Egypt and Israel, gas supply stopped. Israel moved quickly to implement an LNG import project by Q1 2013 and now relies on LNG (as a back-up) as well as increasing indigenous supply.

### *7.2.2.4. Gas-fired compared to coal-fired power generation*

There is widespread recognition that gas-fired power generation is more advantageous compared to other forms of generation, particularly if it is based on cheaper indigenous resources rather than more costly pipeline imports or potentially even more costly LNG imports. But even then, many countries have built large gas to power and wider gas industries based solely on imports. Up until now Kenya has not considered a role for gas-fired power generation other than the LNG to power project which was recently cancelled by the Government (in September 2014). However, there are currently plans to develop two coal-fired power plants, with a combined capacity of 2,300MW, before 2020 – one in Lamu based on coal imports and another in Kitui, likely to be based on indigenous coal resources thought to be available in the area.

In considering the potential for gas-fired power generation in Kenya, in our Base and High Cases we assume that gas gets developed in preference to coal-fired power generation. Thermal power generation is key to any power system as a more reliable and flexible form of power generation (compared to renewable options, for example) and gas is increasingly becoming the preferred fuel globally with many older coal plants being brought offline. The grounds for this are not only due to better economics, but also because gas is cleaner (less carbon emissions) and a more efficient form of power generation. Furthermore, it is faster to develop than coal plant and involves lower upfront capital costs, which often more than offsets the typically higher commodity costs compared to coal so as to provide an overall saving in total electricity output tariffs. The economics of this are shown at a high level below. The economics of other forms of power generation (wind, hydro, geothermal, nuclear) are not compared as these are markedly different to thermal power generation in that they have much higher upfront capitals costs but then have little or no commodity cost (other than uranium for nuclear).

The costs and benefits of gas versus coal as well to other forms of power generation needs to be considered by GoK through more detailed study and part of a Power Sector Master Plan. Below we consider the economics at a high level to help make the case for developing gas-fired power generation in preference to coal. As shown, gas is considerably cheaper than coal if both are based on indigenous resources (even assuming a higher indigenous gas price based on netbacks from international LNG prices) and still competitive if based on LNG imports assuming a crude oil price of $90/bbl.

*Table 7.4: Cost of gas versus coal power generation*

| | Unit | Imported LNG | Imported Coal | Indigenous Gas | Indigenous Coal |
|---|---|---|---|---|---|
| | | CCGT | Coal | CCGT | Coal |
| **Capital Costs** | | | | | |
| Benchmark costs | $/kWh | 1,250 | 2,750 | 1,250 | 2,750 |
| Nameplate **Capacity** | MW | 800 | 800 | 800 | 800 |
| **Total Capex** | **$m** | **875** | **1925** | **875** | **1925** |
| | | | | | |
| **Operating Assumptions** | | | | | |
| **Economic Plant Life** | years | 20 | 20 | 20 | 20 |
| **Capacity factor** | % | 60% | 60% | 60% | 60% |
| **Fuel thermal efficiency** | % | 55% | 37% | 55% | 37% |
| **Pre-tax return on Capex** | | 10% | 10% | 10% | 10% |
| | | | | | |
| **Fuel Price Assumptions** | | | | | |
| **Oil price** | $/bbl | 90 | 90 | 90 | 90 |
| **Coal delivered price** | $/t | | 92 | | 77 |
| **Delivered Price** | $/MMBtu | 14.5 | 3.8 | 7.7 | 3.5 |
| | | | | | |
| **Unit Cost Breakdown** | | | | | |
| **Fuel cost** | $/MWh | 90.0 | 35.4 | 47.6 | 32.3 |
| **Capital Costs** | $/MWh | 24.4 | 53.8 | 24.4 | 53.8 |
| **Variable O&M** | $/MWh | 5.2 | 11.4 | 5.2 | 11.4 |
| **Fixed O&M** | $/MWh | 3.1 | 11.4 | 3.1 | 11.4 |
| | | | | | |
| | | | | | |
| **LR marginal cost** | $/MWh | 122.7 | 112.1 | 80.3 | 109.0 |
| | $/kWh | 12.27 | 11.21 | 8.03 | 10.90 |

*Source: PwC Consortium Analysis*

**Assumptions:**

Capital Costs

- Benchmark capex per unit of capacity are based on recent cost estimates and are discussed in Gas Monetisation Options in section 7.2.3.
- The cost of developing coal-fired power plants is approximately double that of gas and takes several more years to develop. The coal plant assumed does not include carbon capture or clean technologies which would add to capital costs.
- Both gas and coal plants are assumed to be developed in two 400MW phases, with the second phase costing 25% less than the first phase with use of common facilities.

Price Assumptions

- $90/bbl for crude oil is assumed to derive costs for LNG and coal – it is worth noting at lower oil prices, being directly indexed to oil, the economics are more in favour of gas than coal.
- Imported LNG: Delivered LNG prices are based on Asian LNG price levels which (in terms of $/MMBtu) correlate closely to 15% of the crude oil price (in terms of $/bbl). $1/MMBtu is added for cost of regasification in a floating terminal (typically less for conventional terminals).
- Imported Coal: Coal prices trend with oil prices to a much lesser extent – coal price FOB Richard's Bay (South Africa) (in terms of $/tonne) is assumed to be 85% of the crude oil price (in terms of $/bbl). $15/t is added for freight to Kenya and for transporting the coal to the generating plant.
- Indigenous gas: Price for indigenous gas is assumed to be based on netbacks from Asian LNG price levels – with LNG production and export being the best opportunity cost for indigenous production. This may be seen as an upside for producers with the current potential for LNG exports being low and gas volumes insufficient to justify investment. Price assumed takes into account $1.5/MMBtu for transport to Asia and $4.3/MMBtu for liquefaction.
- Indigenous coal: Indigenous coal can be supplied into the international market more easily than gas, which requires costly liquefaction. Hence, as with oil, the price for imported and indigenous coal would be based on parity pricing with international markets. Price assumed is FOB Kenya, which is assumed to be the same as FOB Richard's Bay, South Africa.

Unit Cost Breakdown

- Fuel Costs: Converted from $/MMBtu taking into account the thermal efficiency of each fuel. Gas-fired power plant assumes a standard Combined-Cycle Gas Turbine with net thermal efficiency (or electrical efficiency) of 60%. Coal is based on a hard coal-fired pulverised-fuel steam plant (for imports) or a lignite-fired pulverised-fuel steam plant (for indigenous coal) with new sophisticated technology for drying lignite, both with assumed net thermal efficiency of 45%.
- Capital costs: Unit capital costs are the annuitized capital costs, assuming a 10% pre-tax rate of return, unitized by dividing by total annual output, assuming a utilization or load factor of 60% for both gas and coal.
- Variable operation and maintenance costs: Assumed at 2.5% of annual capital costs, unitized by dividing by total annual output, assuming a utilization or load factor of 60% for both gas and coal.
- Fixed operation and maintenance costs: Assumed at 1.5% and 2.5% of annual capital costs for gas and coal respectively, unitized by dividing by total annual output, assuming a utilization or load factor of 60% for both gas and coal.

### *7.2.3. Gas demand in other sectors (non-power generation)*

In common with many other countries around the world, the development of a domestic gas industry in Kenya is likely to be based on gas use in power generation. Large scale power plants (>500MW) run at base load require sufficient amounts of gas on a constant basis. This is also true for large scale projects where gas is used as a feedstock for gas products, key ones being ammonia (for fertilizer production) and methanol plants. However, unlike these projects, gas demand in general industry takes much longer to be developed, requiring sufficient demand in order to justify the investment to develop a distribution network in different areas around a city or around the country. This is also true for the commercial and residential sectors, but to an even greater extent given much lower and more widespread demand. Below we consider gas use in different industries and as feedstock for gas-related products.

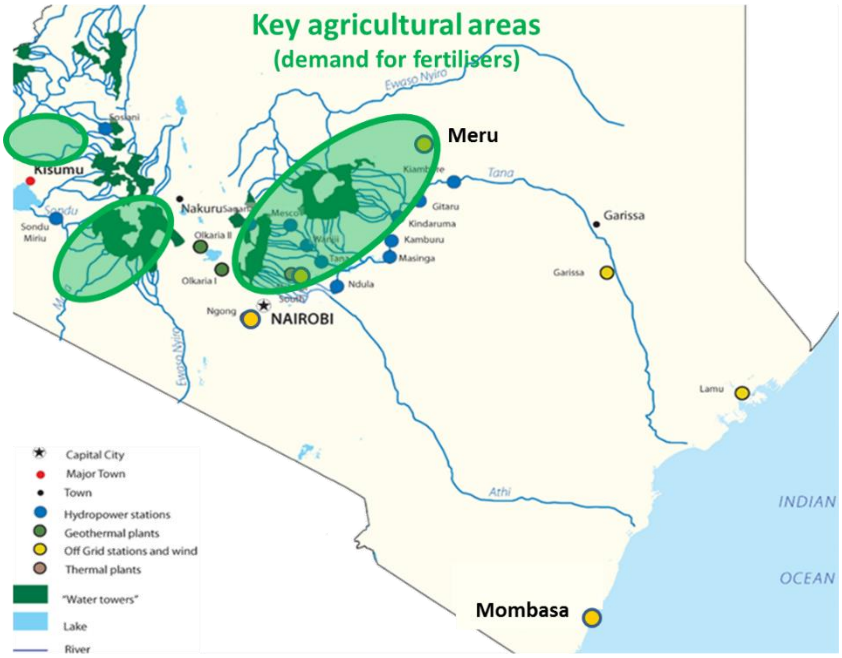
## 7.2.3.1. Gas demand for large scale feedstock

### Production of Ammonia and Methanol

As with Mozambique and Tanzania, if sufficient indigenous gas supply is available to the domestic market, we can reasonably expect a world scale ammonia (fertilizer) or methanol plant to be developed in Kenya with capacity of around 1 million tonnes per annum each (around 3,000 tonnes per day). However, with several projects being developed in Africa, the US as well as in major ammonia and methanol importing countries like India and China, the potential for major exports is somewhat limited.

However, being a major agricultural exporter, fertilizer demand in Kenya is significant. Demand is currently around 500,000-600,000 tonnes per annum, the majority of which is DAP and Calcium Ammonium Nitrate and is largely imported by private companies into Kenya. With demand expected to increase to 1 million tonnes per annum by 2020 and 1.4 million tonnes by 2030, a strong case can be made for developing a world-scale ammonia project, or several smaller ones along key gas pipeline routes. The key agricultural areas in Kenya are mainly inland as shown in the figure below.

*Figure 7.7: Key agricultural areas in Kenya*




*Source: PwC Consortium Analysis*

With common facilities and similar processes, it can be beneficial to jointly develop a methanol and an ammonia plant on the same site. However, methanol demand in Kenya is much smaller than for ammonia/fertilisers, hence any methanol plant would be developed mainly for export with siting on the coast, which reduces the likelihood of developing the ammonia and methanol plants together. A methanol project is likely to face strong competition from other projects being developed globally, including in China, which is the largest consumer.

Hence, even if plentiful gas supply is available, with limited demand we have assumed only one world scale plant is developed. Ammonia and Methanol projects require relatively low cost indigenous gas supplies, hence these projects are assumed to come online post-2020 when any indigenous commercial gas reserves may be in production. This is discussed in more detail in the Strategic Alternatives section 7.3.4.

In terms of gas demand, including 20% gas consumption in the manufacturing process, a world scale ammonia plant with capacity of 1 mtpa is likely to require around 80 MMscf per day or just 0.8 Bcm of gas supply per annum. With similar processes, gas requirements for a 1 mtpa methanol plant are similar.

### Production of petroleum products (gas-to-liquids)

Even though demand for petroleum products is significant in Kenya, gas to liquids (GTL) projects have only been undertaken in a handful of countries and by few players. The main reasons for this are the very complex technology involved and very high project costs. Given the high costs involved, GTL production is only commercially feasible on a large scale requiring significant gas reserves. In a relatively large plant, gas reserves in excess of 4 Trillion cubic feet (Tcf) would be required to feed 450MMscf of gas per day in order to produce 50,000 bbl of liquids per day. Furthermore, approximately 40% of the gas is lost in the conversion process compared to 10% for LNG manufacture which, along with being a much simpler process and lower associated project risk, has meant that producers have tended to opt for monetisation of large gas reserves through LNG production and exports. As discussed below, when considering gas export projects, Kenyan gas reserves potential may not be large enough to consider a large scale GTL plant. For these reasons, and the difficulty in developing such projects, we assume that a GTL project in Kenya is unlikely to be realised and gas demand for GTL production is zero out to 2040.

### *7.2.3.2. Gas demand in other sectors*

#### *7.2.3.2.1. Gas demand in the residential/commercial and industrial sector*

In terms of non-power domestic demand in Kenya, even with considerable indigenous supply, it is unlikely that aggregate industrial, residential and commercial demand will come close to the potential demand for power generation. With a warm climate, demand for space heating in the commercial and residential sector would not likely be required in Kenya, and demand for gas for cooking in the residential sector is likely to be more affordable through electricity or LPG. This is due to the costs of pipeline connection for what may be limited demand, even in densely populated areas, and the costs associated with having to change appliances to use gas.

The pipeline connection cost issue also applies to the industrial sector. With existing manufacturing that may be able to switch to gas supply likely to be sparsely located, it would be very costly to build a large gas network based on such low demand. The costs would have to be passed on to end users and the aggregate costs are likely to be more expensive than alternatives.

If, however, industrial parks were created to encourage new industry that can benefit from the use of cheap indigenous gas supply, then it may be feasible to connect the park to a main gas trunkline pipeline, which would be supplying an anchor project, such as a large power generation or gas products project. Gas demand from such industrial parks is typically less than 0.5 Bcm/yr (e.g. only some of the largest industrial complexes in Europe get up to this level) and hence much lower than for the other gas projects described above. However, if several parks are established around the country, then the aggregate demand could represent a large portion of total gas demand in the country. With gas uptake in the industrial sector likely to be dependent on the development of new industrial parks along gas networks supplying larger anchor projects, there is currently no credible basis for estimating total potential gas demand in the industrial sector in Kenya. However, in order to provide an indication of the scale of typical manufacturing plants/sites in terms of gas consumption, we have taken examples of actual gas demand from plants/sites that are directly connected to the gas transmission network in the UK. These are discussed in more detail on the Monetisation Options section.

#### *7.2.3.2.2. Gas demand in the transportation sector*

Natural gas use in the transport sector is mainly through Compressed Natural Gas (CNG) or LNG. In terms of a fuel in transport, LNG and CNG only differ in how they are stored on the vehicle. In terms of distribution and fuelling infrastructure, CNG and LNG differ considerably. CNG uses natural gas in a gaseous state and typically requires a well-developed natural gas pipeline transmission and distribution network. It is more widely adopted than LNG as a fuel in transport as it is used in cars and buses with more options for fuelling points in and around populated areas. LNG in road transport only works if a country has an LNG import terminal or export plant, where LNG can be tapped off before the LNG is regasified and sent into the network or loaded onto a ship for export. Where gas pipelines are not in place or is not economic to develop, LNG trucking (LNG transport via LNG road tanker) to LNG storage depots around the country is an alternative to CNG. As this may be less economical, LNG as a fuel in transport is better suited to Heavy Goods Vehicles (HGVs) travelling long distances without having to stop to refuel so often.

Compressed Natural Gas (CNG) would really only be feasible if the gas pipeline network were already established and the Government invested in fleets of CNG-based buses or taxis, as some other countries have done (e.g. India and Thailand). Such fleets would only be possible in cities connected to major pipelines. Privately owned public transport makes up a large portion of the automotive fuels market, and is considerably larger than the public transport sector. Hence, unless the Government invests in a large new fleet of public transport, gas infrastructure and CNG fuelling stations in and around major cities, then demand for gas in public transport would be limited. If the infrastructure is developed for the public sector transport, then there may be some uptake from the private sector. But it would be difficult to base the investment required solely on potential uptake from the private sector. Furthermore, demand for electric powered vehicles is more likely following recent trends in developed nations.

In terms of LNG, Kenya previously considered developing an LNG import terminal. However with the discovery of indigenous gas resources then this project, if developed, is likely to be required only in the short term (c. 5 years) to meet power generation needs and to facilitate the development of indigenous gas resources. Investors/transporters are unlikely to invest in LNG use for such short periods. In terms of LNG exports, we assume a project can only be developed in the High Case for Supply Potential. So from the outset, LNG in road transport is currently limited in Kenya. If an LNG export project *is* developed, then HGV road transport is common between Nairobi and the port of Mombasa and between Nairobi and other cities to the North and West. Furthermore, existing HGVs can be relatively easily converted to run on LNG. However, in order to switch HGV fleet operators would need to choose to install depot-based refueling facilities adjacent to the LNG plant such that LNG can be loaded onto the LNG road tanker for transport to fuelling depots. A major challenge would then be for the requirement for additional depot-based refueling facilities along the main routes used by the HGVs. This issue can be overcome if operators have a large fleet or are willing to share a refueling facility (and the associated costs involved). However, with new rail networks being planned in Kenya, HGV transport may be on the decline. Any new investment in LNG fuelled HGV trucks may be limited to one or two privately owned fleets. Due to this and the currently low probability of developing and LNG export project, demand for LNG in road transport is assume to be negligible for the purposes of this study.

## *7.2.4. Conclusions*

LNG Export

- Many countries that have discovered natural gas resources have opted to monetize such resources through developing large scale LNG and/or pipeline export projects.
- In some cases this has been to the detriment of the development of their own local gas industries – which are mainly predicated on the development of gas-fired power generation.
- Kenya, unlike Tanzania, Mozambique, Nigeria, and Algeria, currently does not have sufficient amounts of gas to consider developing an LNG export project in the Base Case Supply Potential scenario.
- However, this assumption is based on limited amounts of information with estimates being taken from only some licensing blocks that are at early stages of development, with others yet to begin detailed exploration activity.
- Hence, as exploration activity increases more gas resources may be discovered and it will be critical for the GoK to encourage further exploration and keep this option open for the future.

Anchor Loads

- However, from the information available, Kenya does potentially have more than sufficient amounts of gas resource to consider developing a local gas industry.
- As with many other countries, this will almost certainly have to be based on anchor base loads such as gas-fired power generation, which can justify the costs of pipeline infrastructure and so facilitate the development of gas use in the industrial sector.
- There is some potential for gas use in the production of ammonia and methanol as an alternative/additional anchor load. However, the potential for commercial exports of these gas products may be challenging given the large number of projects coming online in other countries to feed a limited international market, with major importers also developing their own projects.
- The projected demand for ammonia products within Kenya could justify a new plant to feed this market.

Gas-Fired Power Generation

- In the Base Case we assume 1,085MW of gas-fired power generation is developed around 2025 (including switching 285MW from being oil-fired), and a further 800MW is developed in each of the periods around 2030, 2035 and 2040, bringing the total gas-fired power generation capacity to 1,885MW (1.8 Bcm/yr) by 2030 and 3,485MW (3.3 Bcm/yr) by 2040.
- We have assumed gas-fired power generation is developed only once indigenous supply comes onstream, expected post-2020. However, LNG imports in the short term may mean gas-fired power generation is developed earlier and provides additional assurance to the upstream sector.
- Kenya, currently relies on around 2,000MW of power generation capacity. Whilst this may be insufficient to meet requirements, going from a base as low as this to the Government's targeted 15,000MW by 2030 may be optimistic from a demand perspective.
- With geothermal power generation expected to make up a large proportion of the power generation mix (targeted to reach 5,000MW by 2030), followed by wind (2,000MW), the potential for other forms of power generation (including gas) is limited.
- In addition, the potential development of coal-fired power generation would take market share away gas-fired power generation, which is lower cost, cleaner and quicker to build than coal.
    - In our Base Case assumptions for gas-fired power generation we assume no coal-fired power generation gets developed.
    - This is contrary to the Government currently considering the development of a 1,000MW coal power plant in Lamu.
    - High level economic analysis suggests that power generation from LNG imports is competitive with imported coal and indigenous gas is much more competitive than indigenous coal.

- Kenya is currently in a state of power generation capacity oversupply with potential financial consequences for the Government and end users – this is not expected to last long as demand continues to grow including further electrification.
- Before pursuing the development of any further additional power generation, the Government should:

- Undertake detailed Power Sector Master Planning – in addition to the LCPDP initiative – and through it project power demand growth more accurately and understand the risks of capacity oversupply.
- Fully understand the potential for geothermal power generation as 5,000MW addition may be optimistic given that total global geothermal capacity is around 12,000MW, one third of which is in the US.
- Understand in more detail the costs and benefits of developing coal rather than gas-fired power generation and the impact this may have for the upstream oil and gas sector in Kenya.
- One of the key advantages is that gas-fired power generation can be developed in 24 months, whereas coal plants typically take longer to build.
  - This will be important if for example geothermal is not realized to the extent currently expected.
  - However, on the other hand, planning the development of gas-fired power generation on this basis will not provide upstream gas producers the assurance they require to make investment in gas production and start to produce gas for the local market – which typically could take 3-5 years, or longer if policy/terms are still being agreed.

# 7.3. Gas Monetisation Options, Infrastructure and Operational Requirements

## 7.3.1. Introduction

This section aims to provide an overview of the market, commercial, and technical aspects of 1) Gas-fired power generation projects, 2) Ammonia projects, 3) Methanol projects, 4) Gas use in the industrial sector, and 5) LNG export projects. For each we provide an overview of the market in terms of supply and demand, trade, pricing and the drivers for each. We discuss the general physical set up of each project and the technical process of how feedgas is used or converted into products and delivered to market. We consider options for project scale for projects in Kenya based on potential gas supply availability and demand-related constraints. Based on this, we discuss and estimate plant and supporting infrastructure capex and opex and how these have evolved more recently. On commercial aspects, we provide an overview of the types of players involved along the chain and options for GoK and National Oil Companies (NOC) participation, giving examples from other projects around the world.

## 7.3.2. Gas-fired power generation projects

### 7.3.2.1. Background

***Note:** Through this section when discussing gas-fired power generation we will generally be referring to Combined Cycle Gas Turbines (CCGT). This is the combination of the Brayton cycle of the gas turbine with the Rankine cycle of the heat recovery steam generator (HRSG). In some cases we will refer to the re-firing of existing oil plant to gas, which may remain in open cycle if the age of the plant makes full combined cycle uneconomic. The assumption will be that these plants will be running at base load or at least mid-merit and not peaking, where the gas usage would be much lower. CCGTs and gas-fired power generation will be used interchangeably.*

Thermal power plants (gas/coal/oil) are generally faster and cheaper to construct than other forms of power generation (hydro, nuclear and wind). Within the thermal category, gas-fired power plants top the list based on these same criteria. However, the commodity or operating costs of gas/oil/coal are much higher than for hydro, nuclear and wind power plants, which have minimal operating costs. With the abundance of internationally traded coal and large deposits in many countries, coal-fired power generation is the most common form of power generation. However, given its high efficiency as a fuel, low pollutant properties and increasing availability, gas-fired power generation is growing rapidly – substituting fuel oil and diesel and replacing older coal-fired power plants.

#### 7.3.2.1.1. Supply and demand

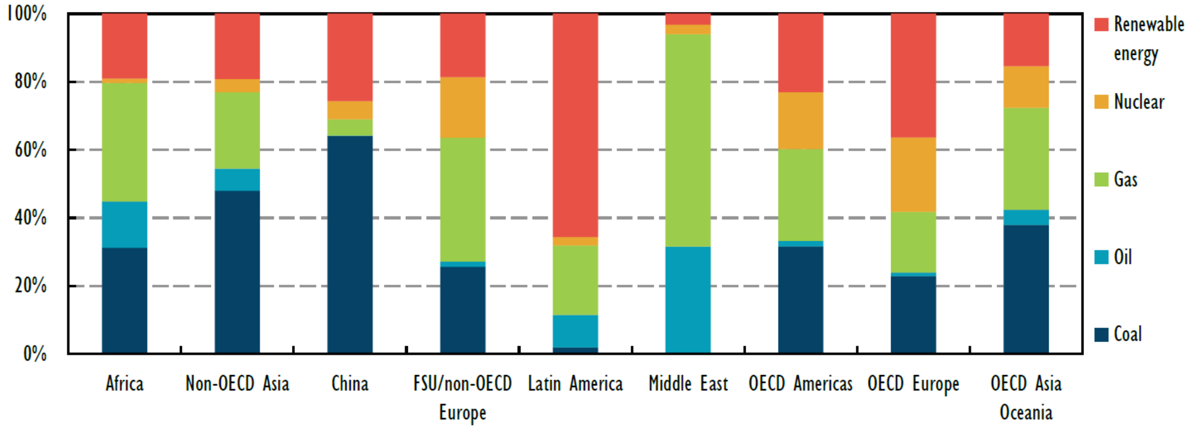
The lack of infrastructure to import gas has meant that gas consumption in power generation has mainly been confined to regions with an abundance of gas supplies. Korea, Taiwan and particularly Japan are exceptions to this is and built LNG import terminals to secure LNG supply primarily for power generation when the LNG industry was first starting up in the 1970s and 1980s.

More recently, many other countries are turning to LNG as a way to secure gas supply for power generation. LNG is generally a cheaper substitute for countries using fuel oil or gasoil/diesel as fuel in power generation and the process of converting the power plant is relatively straightforward. In some countries, developing new gas-fired power generation is the fastest way to alleviate power shortages.

In OECD countries gas-fired power generation has recently experienced strong competition from wind power. The main reasons for this are the increase in gas prices influenced by environmental concerns, high oil prices (particularly in Southern Europe and Asia), supply concerns (with reliance on a few large supplying countries in different regions) and in Europe the imposition of a tax on carbon emissions, which do not apply to wind power.

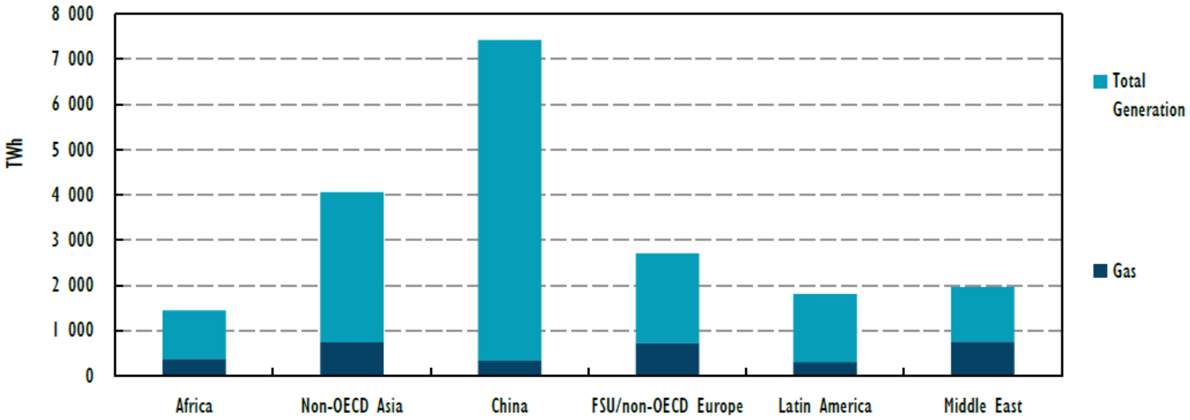
Gas' share in the power generation mix globally and in different regions is shown below. 'Renewables Energy' includes solar, wind, geothermal, hydro, and some forms of biomass. In OECD countries, renewables are approximately evenly split between wind and hydro. In Latin America, China and Africa, renewables are predominantly hydro.

*Figure 7.8: Gas' share in the power generation mix (projection 2019)*




*Source: IEA*

*Figure 7.9Gas generation against total generation by region (projection by IEA for 2019)*




*Source: IEA*

In Africa, gas-fired power generation makes up 20% of the power generation mix. This is mainly from countries in the Northern and Western parts of the continent with large gas reserves or gas importing countries adjacent to these. In total there are 15 countries with gas-fired power plants. Some countries such as Algeria, Libya and Morocco rely almost solely on gas-fired power generation. Countries in the East, Central and Southern parts of the continent are largely reliant on a combination of hydro power and diesel-fired power generation. Only a few countries, including Senegal, Botswana, South Africa and Zimbabwe, have coal fired power plants. South Africa is the only country with a nuclear power plant and, along with Kenya, is one of the few African countries with operational wind power.

In Kenya, as discussed earlier – Gas Demand analysis, approximately 98% of power generation capacity at 30 June 2014 is made up of hydro, geothermal and heavy oil-fired power generation, with wind, solar and biomass making up the rest. Up until two years ago, hydro made up more than 50% of power generation capacity before the new geothermal projects came online. There is currently no gas-fired power generation in Kenya, but with recent discoveries of gas resources, which may be insufficient to underpin an LNG export project, there is good potential for using the gas locally, with power generation being the best option. In our Base Case, we assume 1,085MW of gas-fired power generation based on indigenous resources is developed around 2025, including switching 285MW from being oil-fired. This can be developed sooner depending on when indigenous production comes online or based initially on gas supply from imports of LNG until indigenous supply comes online, but timing is also subject to power demand requirements. A further 800MW is assumed to be developed in each of the periods around 2030, 2035 and 2040, bringing total gas-fired power generation capacity to 1,885MW by 2030 and 3,485MW by 2040.

### 7.3.2.1.2. Pricing

#### 7.3.2.1.2.1. Gas and power price relationship

In countries with well-developed and liquidly traded gas and power markets, gas-fired power generation is usually the marginal source of power generation and short term and long term changes in gas prices are usually passed through to power prices. More recently, large investment in wind power in Europe has brought strong competition and in some instances has reduced gas' role from providing base and mid-merit load power supply to now operating mainly at mid-merit and as back up for wind on less windy days. The commodity cost of gas - influenced by many factors, and the tax on carbon emissions are key factors for gas-fired power generation's reduced role in Europe. In East Asia, the situation is similar to Europe pre-wind, where gas-fired power generation provides both base and mid-merit power supply and high reliance on costly LNG for power generation is passed through to power prices and to end users. In the US, with less stringent carbon laws and much lower gas prices due to oversupply from recent large scale shale oil and gas production, gas-fired power generation competes strongly with coal-fired power generation.

In countries with large gas reserves and with less developed or export-focused gas markets, the price of feed gas to power generation is usually low (compared to international gas and fuel oil prices) and sometimes fixed, thereby making such plants competitive against other forms of power generation, providing the country with a relatively cheap power supply. Despite being able to produce gas at low cost, some countries still choose to subsidise the cost of gas into power generation. Key examples are Nigeria, Saudi Arabia, and Algeria.

#### 7.3.2.1.2.2. Power Prices in Kenya

Kenya's electricity prices are regulated and approved by the Energy Regulatory Commission. The process by which tariffs are set is defined in the Energy Act, 2006 and has been designed to provide a systematic process for ensuring cost reflectivity, simplicity, and long-term stability for consumers and producers.

Energy prices are determined using an Aggregated Revenue Requirement (ARR) methodology, whereby the following factors are taken into account for Kenya Power: Rate base (net assets, working capital); capital related revenue requirement (cost of equity, cost of debt); cost of electricity purchase (capacity charges, energy charges); operations and maintenance costs (including those for KETRACO and REA); fuel cost charge; foreign exchange rate fluctuation adjustment; inflation adjustment; water Levy.

Kenya also subscribes to a Feed-in-Tariff (FiT) policy which was introduced in 2008, to attract investment in, and development of small and mini-hydro plants by the private sector. The Policy was revised in January 2010, and a second revision was later made in December 2012, with the intent of improving the calculation model. The FiT Policy is designed to provide for review every 3 years. The objective of the Policy is to essentially allow power producers to sell renewable energy (i.e. wind, biomass, small hydro, solar, biogas and geothermal) at a pre-determined tariff to the off-taker i.e. KPLC for a fixed period of time. This ultimately provisions for:

- Investment security for renewable energy generators;
- Reduced transaction and administrative costs and delays; and
- Encourages efficiency in power production.

Significant advantages pegged to the introduction of the FiT include amongst other, the enhancement of energy supply security by reducing reliance on importation of fuels, and a reduction in greenhouse gas emissions.

Since the introduction of the FiT in 2008, there has been an increase in investments in small hydros and IPPs for other renewable energy projects.

## Cost of Power Generation in Kenya

It is important to note, each power plant has its own specified capacity charge and energy charge as indicated in its Power Purchase Agreement with KPLC. Fuel costs and fuel displacement costs also vary across plants with the same fuel source. The Standard FiT for renewable projects that have an installed capacity of above 10MW is as follows:

*Table 7.5: Cost of power generation in Kenya*

| | Installed Capacity (MW) | Standard FiT (US$/KWh) |
|---|---|---|
| **Wind** | 10.1 – 50 | 0.11 |
| **Geothermal** | 35 – 70 | 0.088 |
| **Hydro** | 10.1 – 20 | 0.0825 |
| **Biomass** | 10.1 – 40 | 0.10 |
| **Solar (Grid)** | 10.1 – 40 | 0.12 |

*Source: FiT Policy 2nd Revision December 2012*

The table above illustrates the lowest tariff at US$ 0.0825/kWh for Hydro, followed by US$ 0.088/kWh for Geothermal. N.b. these tariffs do not include the costs of distribution to end users.

As per KenGen's Company Report for the financial year end 2014, the revenue in US$/kWh (based on KenGen sales alone) also demonstrates hydro as the lowest cost source of fuel, followed by Geothermal – with Wind being the most expensive at US$ 0.077/kWh, followed by Thermal at US$ 0.06/kWh:

*Table 7.6: KenGen revenue per power source*

| Revenue US$ / Kwh** | 2013 | 2014 |
|---|---|---|
| **Hydros** | 0.023 | 0.026 |
| **Geothermal** | 0.042 | 0.037 |
| **Thermal** | 0.079 | 0.060 |
| **Wind** | 0.075 | 0.077 |

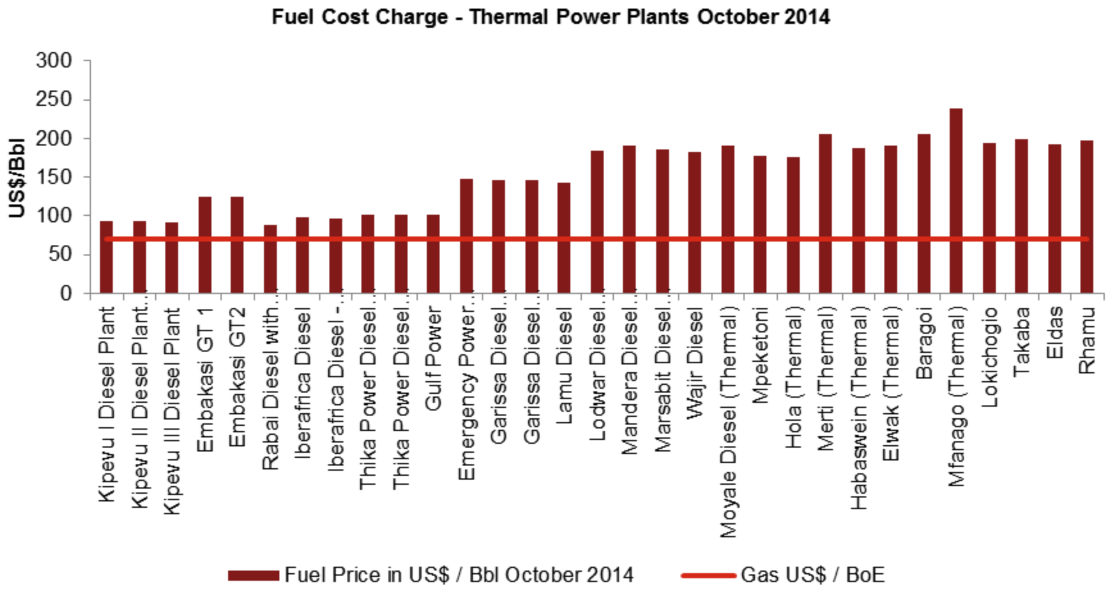
*Source: PwC Consortium Analysis, KenGen Company Report FY14 (Based on revenue per power sources and units sold)*

** Note – The revenue US$/kWh presented in the table above does not include costs of distribution to end users, steam charges, inflation and foreign exchange adjustments. This is purely an illustration of revenue per unit sold for each power source based on KenGen's sales. It should also be noted that KenGen's costs for thermal and geothermal power generation are generally below those for IPPs.

### Fuel cost of Thermal power generation

KPLC publishes Fuel Charge Costs for thermal power plants in Kenya – largest ones being the Kipevu, Rabai and Iberafrica plants – most of which run on Medium Speed Diesel. The graph below represents the fuel costs for each thermal power plant in US$/barrel for October 2014.

*Figure 7.10: Fuel cost charge of thermal power generation, 2014*




*Source: PwC Analysis, Kenya Gazette October 2014*

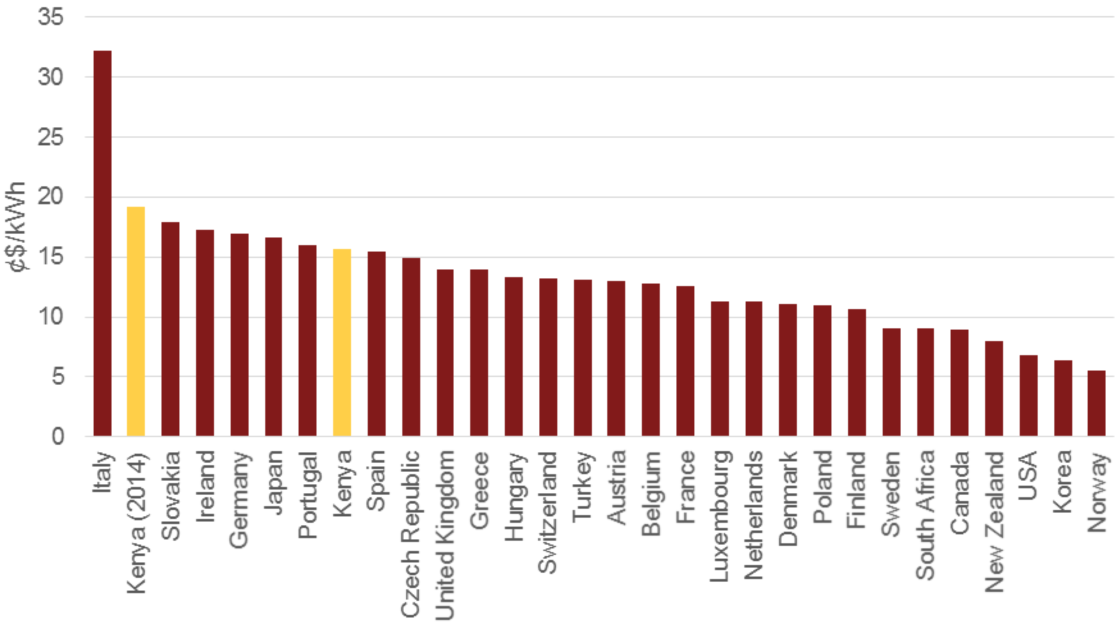
These oil-fired power plants can be re-fired by converting to run on gas supply as has been previously planned for the Kipevu and Rabai plants in Mombasa. The cost of imported LNG, which is also largely linked to oil prices, is generally cheaper than diesel and even fuel oil. Prices have recently been between US$ 12-15/MMBtu (at oil price levels of US$ 80-100/Bbl). The cost of indigenous gas supply is likely to be much lower than this.

### Comparison of power prices

KPLC adopts a merit order dispatch approach; this is particularly beneficial in circumstances where power supply exceeds demand. In which case, economic merit order for a particular month is based on the previous months' costs. Thermal power plants generally rank below hydro and geothermal. However each independent power producer has a unique energy charge, fuel cost charge and capacity charge as defined in their PPAs (KenGen on the other hand has uniform costs across power plants with the same source of energy), therefore some hydro power plants may be considered more expensive than geothermal power plants depending on plant availability and age of the plant, amongst other factors. Given Kenya's heavy reliance on hydro power as the main source of generation, unreliable hydrology has hampered the sector and as such the alternative source of energy is Thermal. This however results in expensive fuel sources for generation to replace hydro impacting on the overall power price.

Taking into account the cost of distribution, foreign exchange adjustments, inflation as well as fuel costs, Kenya ranks as one of the most expensive countries for electricity supply. In 2013, average electricity prices to industrial consumers were around ¢US$ 16/kWh. This is lower than the ¢US$ 17/kWh observed in Germany (which has made large investments in wind power) and Japan (which is reliant on major imports of premium priced LNG), but higher than prices of ¢US$ 12-14/kWh in the UK, Turkey and France, ¢US$ 9/kWh in South Africa and ¢US$ 7/kWh in the US and South Korea.

*Figure 7.11: Electricity prices to industrial sector (2013 average)*




*Source: IEA, Regulus*

Since 2013, average power prices to industrial consumers have increased in Kenya to around ¢US$ 19/kWh in the year up to August 2014. The main reason why power prices are so high in Kenya is due to a lack of reliable power generation, having to increasingly rely on costly diesel-fired power generation for baseload power supply and even more costly smaller emergency power producers for peak load power supply.

However, as stated in its National Energy Policy, the Kenyan Government's target is to reduce the general level of power prices to around ¢US$ 8/kWh by 2017. This is expected to be achieved through the addition of cheaper geothermal power generation, replacement of costly diesel and fuel oil power generation with imports of LNG (which is now no longer being considered), and improved infrastructure.

Gas-fired power generation from indigenous gas resources will have an important role to play in reducing power prices. With uncertainties around many other forms of power generation (e.g. low quality steam from geothermal, intermittent wind, unreliable hydro), gas-fired power generation could be key to providing baseload reliability of power supply and at the same time help GoK meet its objective of reducing electricity tariffs. It is this reliable baseload power that will ultimately lead to large reductions in power prices.

GoK is currently planning the development of two coal-fired power plants which can also bring reliable baseload power supply. However, in terms of costs of power production from these baseload sources, LNG fired power production will be lower cost than diesel and HFO-fired power generation, but similar in cost to coal-fired power generation – assuming all fuels are imported and depending on the relative costs of oil to coal. However, Kenya also has potential for indigenous gas and coal production, which would be cheaper than costs of imports, and hence power generation from indigenous gas and coal is expected to be even more competitive. Of the two, as discussed in the Gas Demand section, indigenous gas is expected to be lower cost than indigenous coal. Furthermore, with gas being cleaner (lower emissions) and more efficient, as well as quicker to develop with lower capital costs involved, it represents the preferred option as has been seen in many countries globally.

It will be important to consider the role of baseload gas power generation in terms of Power Sector Master Planning. Hence, a Power Master Plan should be well aligned with options and recommendations from the Gas Master Plan. We discuss this in more detail in our Recommendations.

## *7.3.2.2. Production and transport*

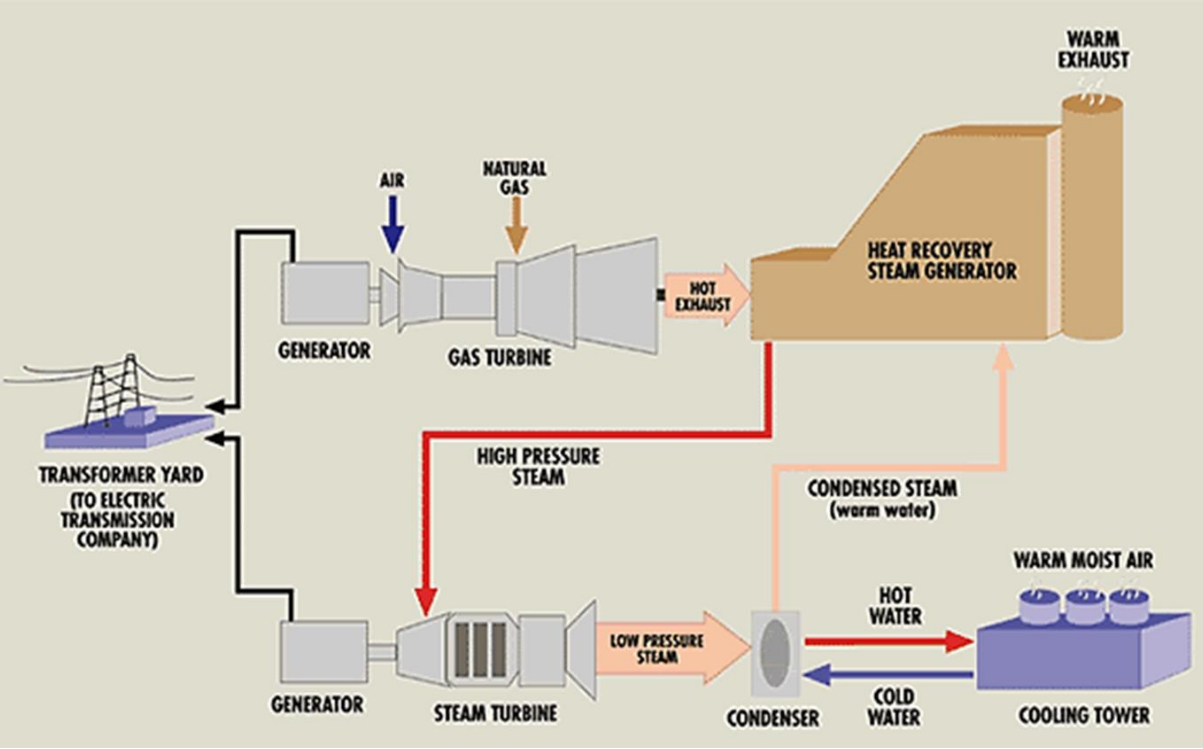
### *7.3.2.2.1. Gas-fired power generation*

Gas-fired power generation is mainly through burning the gas in Combined Cycle Gas Turbines (CCGT), which is the combination Brayton cycle gas turbine with the Rankine cycle steam turbine.

In the Brayton cycle, combustion air is mixed with gas and ignited. The resulting hot gases are expanded through the gas turbine, driving the generator and converting rotational energy to electrical power.

In the Rankine cycle, water is heated to produce steam which is expanded through a steam turbine, driving an electrical generator. The heat required for this process is derived from the hot exhaust gases from the Brayton cycle through a heat recovery steam generator (HRSG) with steam temperatures of between 420-580 degrees Celsius. The exhausted steam is then condensed and pumped back to where it was heated. Heat is removed from the cycle by the circulating water system.

*Figure 7.12: Working principle of a combined cycle power plant*




*Source: NIPPC*

New CCGTs have a thermal efficiency of around 60%. This is much more efficient than a single cycle power plant with thermal efficiencies of around 35-40%. Thermal efficiency is impacted by ambient air temperature – as ambient air temperature increases, plant output decreases due to reduced mass flow through the turbine itself.

Gas and steam turbines are relatively standardised in terms of design and are sold by different manufacturers as modules. There are many different configurations for CCGT power plants, but typically each gas turbine has its own associated HRSG, and multiple HRSGs supply steam to one or more steam turbines. CCGTs can come as single-shaft or multi-shaft configurations. The single-shaft system consists of one gas turbine, one steam turbine, one generator and one Heat Recovery Steam Generator (HRSG), with the gas turbine and steam turbine coupled to the single generator. The multi-shaft design enables two or more gas turbines to operate in conjunction with a single steam turbine, which is more economical, though more complex and more costly (by approximately 5%). A 2x1 configuration will consist of two gas turbines, two HRSGs supplying one steam turbine. There can be various configurations e.g. 1x1, 3x1 or 4x1, where the steam turbine is sized to the number and capacity of the gas turbine/HRSG.

The construction period for a CCGT power plant is around 18-24 months and has an economic life of around 30 years.

### *7.3.2.2.2. Power transmission*

Gas-fired power plant siting depends mainly on options for power transmission versus gas transmission, i.e. generating power further from demand centres and transporting power by wire, compared to transporting gas to power plants located closer to demand centres. We discuss this in more detail in the Strategic Alternatives section but highlight some general costs and benefits below.

Electric-power transmission is the transport of electrical energy generated from power plants to electrical substations located near demand centres. Most transmission lines are high-voltage (110 kV or above) three-phase alternating current (AC). High voltage reduces the energy losses over long distances. Power is usually transmitted through overhead power lines and requires relatively large rights-of-way (20-30 metres for 110kV or even more for higher voltage lines). Underground power transmission is also an option requiring less rights-of-way but is significantly more expensive than overhead transmission and therefore limited to use in urban areas. A key limitation of electric power transmission is that electrical energy cannot easily be stored, and must therefore be generated closely correlated with expected demand. If demand exceeds supply, transmission equipment can fail leading to brownouts and blackouts. It is therefore important for networks to be based on multiple sources of power generation and wide networks.

In developing markets, gas pipeline transmission may be cheaper to develop than power transmission if power generation requirements exceed 3,000MW. Capital costs for medium sized gas pipelines delivering gas to some 3,000MW of generation capacity are estimated to be around US$ 2-3 million per mile. Power transmission is however cheaper to operate and maintain, but can incur losses of as much as 10%, whereas this is much lower for gas transmission (generally 1-2%).

There are many other factors that need to be taken into account in considering power versus gas transmission, including specific power and or gas demand requirements along main transmission routes to major power demand centres. If power requirements are mainly in one or a few key areas, then gas transmission would be preferable from an energy planning perspective allowing any potential gas demand to be supplied more economically along the way. Gas pipelines can also serve additional (smaller) power plants along main gas transmission routes but the reverse is not possible. If power will be consumed more frequently along the way to major power demand centres then a case for power transmission can be made. However, this is more likely to be the case in well-developed or well-populated areas and is unlikely to apply in Kenya.

### *7.3.2.3. Project scale*

CCGT power plant turbine designs are now fairly well standardised across manufacturers. The F-class is considered to be a typical large scale CCGT unit with a rating of around 400MW – consisting of a 270MW gas turbine and a 130MW steam generator, though configurations can vary with different manufacturers. Maximum ratings for F-class plant are currently 300MW for a standalone gas turbine and 450MW for a single shaft gas and steam turbine configuration. Larger plants benefit from economies of scale providing savings of approximately 25% on twin installations (e.g. 2 x 400MW). Savings are mainly through sharing of civil works, grid connections, fuel facilities and other support infrastructure.

The CCGT plant currently planned in Dongo Kundu in Kenya is expected to have a rating of 700MW. Going forward, our assumptions on plant rating for future developments will be based on 400MW twin units (i.e. 800MW) using a multi-shaft configuration. It would be more economical and generally more optimal to develop large twin units over time every number of years rather than build smaller units more often.

In terms of gas supply requirements, an 800 MW CCGT plant would require 75 MMscf per day or 0.75 Bcm per year (assuming thermal efficiency of 55% and a load factor of 60%) or approximately 0.73 Tcf of gas reserves assuming a 30 year project life time.

### *7.3.2.4. Project costs*

As discussed above, upfront capital costs for developing thermal power plants is much less than for other nuclear, wind and hydro options. CCGT power plants are typically lower cost than coal-fired power plants to construct. However, fuel costs constitute a much larger amount for thermal power plants and, typically, the cost of coal is cheaper than gas if both are available locally.

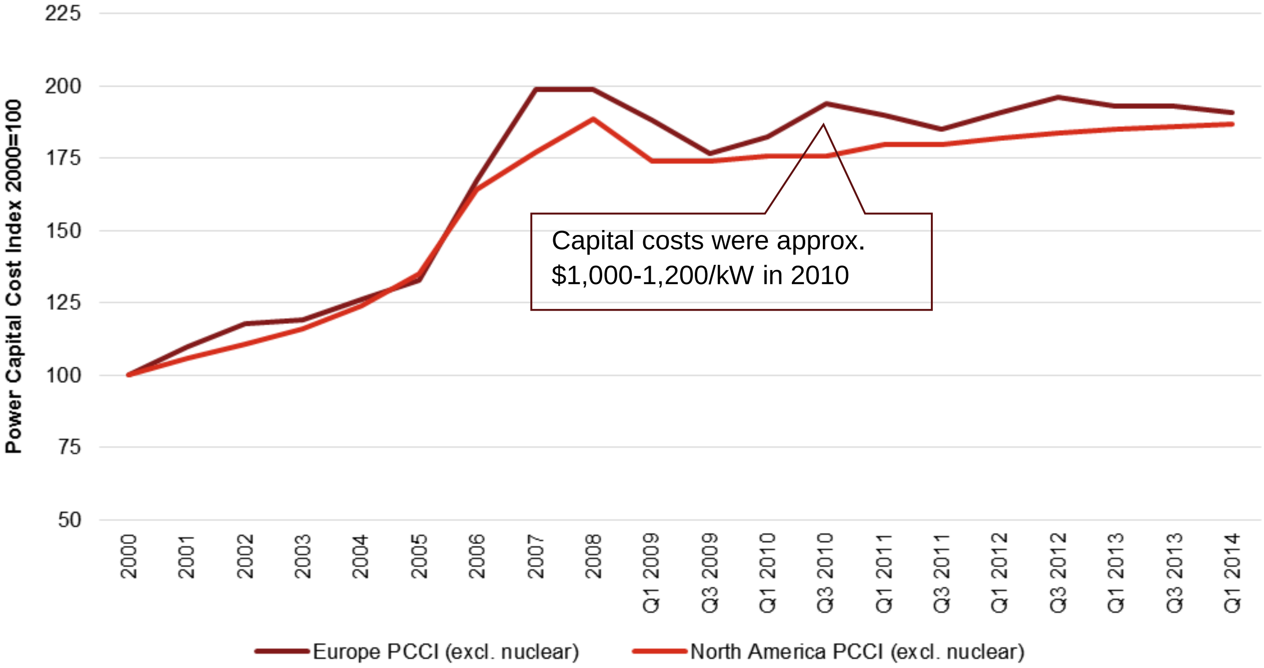
In the case of Kenya, gas may be produced cheaply but producers would require sufficiently high prices in order to make it worthwhile to supply gas to the domestic market and to undertake additional exploration and drilling activities. These prices could conceivably be based on netbacks from international LNG prices or even the cost of coal imports as an alternative for supplying gas domestically or to gas-fired power generation, respectively. Kenya also has large coal deposits which can also be produced cheaply and is likely to cost less than gas. However, the coal produced is expected to be of low quality and may mean gas is competitive on an energy equivalent, whole cost basis.

In terms of capital costs, with manufacturing in specific locations around the world by a number of key players (including Alstom, General Electric, Siemens, Westinghouse, Mitsubishi), competition between manufacturers is reasonably high. With most manufacturing done offsite and completed modular units (largely standard in design) delivered to project locations, costs for CCGT units are similar around the world. Obviously prices differ based on relationships, scheduling, number of units ordered and specific terms agreed with manufacturers and EPC contractors.

In terms of cost breakdown, the main rotating parts (turbines and generators) cost around 50% of the EPC price. The HRSG, condenser and cooling system cost around 20%, plus 15% for civil works, and the remainder being for the rest of the plant.

CCGT plant costs vary with market conditions and supply and demand for units globally. Capital costs have tended to be cyclical following cycles of high demand and over build, followed by low demand and oversupply. However, as discussed in relation to the costs of LNG liquefaction trains, since early-mid 2000s, global price inflation and high cost of oil and other commodities, in particular metals, has meant that the cost of building a CCGT power plant has increased markedly over the last decade. Prices spiked in 2007/8 due to record high oil and metal prices, full order books and depreciation of the US Dollar. Since 2008, prices have remained relatively flat with some continued cyclicality (in Europe) as shown in CERA's power plant capital cost index below.

*Figure 7.13: Europe and North America power capital cost index*




*Source: IHS CERA, QED estimate of 2010 costs*

Based on cost reported by major manufacturers, capital costs for CCGTs in 2010 were in the range of around US$ 1,000-1,200/kW or US$ 1-1.2 million for every MW of capacity. Since then costs have not increased by much and are expected to remain relatively flat over the next year, assuming no major changes in global inflation and commodity prices. Into the medium term of 2020-2025 and beyond, when Kenya may be expected to start to construct more gas-fired power plants based on indigenous gas reserves, demand for CCGTs globally would still be expected to remain strong and hence costs are not expected to drop by much from current levels.

Based on this, in the Base Case we estimate total installed capital costs for a gas-fired power plant in Kenya to cost US$ 1,250/kW for a 400MW plant and 25% less for the second 400MW unit (as discussed above) giving an average cost of US$ 1,150/kW or a total cost of US$ 875m, in Real US Dollars 2015 terms.

In the High Cost and Low Cost Cases, we assume average per unit capital costs of US$ 1,300/kW and US$ 750/kW for an 800MW CGCT plant, giving total installed capital costs of US$ 1,050m and US$ 600m, respectively.

In terms of operating costs (cash costs at site level), the main elements are:

- Maintenance cost: estimated as 1.5% of the capital cost each year

- Labour costs: relatively given low number of staff required to run the plant
- Local and national taxes

In general, total annual operating costs can be estimated to be approximately 4% of the total capital cost.

### *7.3.2.5. Players and options for Government or NOC participation*

In many countries, power generation, transmission and distribution is owned and operated by state-owned utilities. These markets tend to be less densely populated, less well developed and have lower per capita power consumption.

A step away from this is for the transmission and distribution networks to be state-owned but for some power generation to be owned by independent power producers (IPPs) and some by the state, or jointly through public-private partnership (PPP), with all generators selling most or all their electricity to the state-owned electricity company. This is currently the case in Kenya where the setup of IPPs is governed under the PPP Act. Advantages of retaining state-owned electricity distribution is that the Government can focus on the development needs of the country, e.g. expanding and extending the grid as population changes in different areas.

In developed markets, the state has little involvement in power generation, but can sometimes play a role in regulating the transmission and distribution of power, and can influence both the form and level of new investment through energy policy and regulatory incentives. This is currently the case in the UK, where power generation and supply is mainly provided by six large vertically integrated independent utilities who all compete against each other.

Other developed markets have liquidly traded power markets or a power pool where suppliers can purchase power from the market and supply it to end users. In some larger markets, such as the US and India, power generating and supply can be split by state with different utilities operating in each state.

In terms of the different types of power generation, hydro and nuclear are more costly with considerable development risk and therefore tend to have more Government involvement in their development and operation. With the energy source being free or low cost, operational risks are low. In contrast, thermal power plants are cheaper to construct, but then have to source energy supply and may take significant commodity price risk through its operational life, and tend to be developed by independent power producers. To some extent they also take less political and environmental risk than nuclear and hydro. However, in Kenya, Kengen, the largest power generator, which is largely state-owned, is expected to play a large role in the development of thermal power plants.

### 7.3.3. Gas product export projects

#### 7.3.3.1. Background

Gas can be processed and converted into two internationally traded products namely, ammonia and methanol.

Ammonia is produced by reacting nitrogen (from the air) with hydrogen (from gas or naphtha) at high pressure and temperature. Ammonia is a colourless gas but is also a good refrigerant and is therefore usually stored, transported and sold as a liquid. Methanol is made by reacting carbon monoxide with hydrogen, under high temperature. Methanol can also be produced from coal – but this is only common in China. Ammonia is predominantly used in the manufacture of fertilizers through derivatives like urea. Methanol is a clear liquid used in the production of chemicals, which in turn are used to produce everyday products, such as building materials, foams, resins, plastics, paints and polyester.

Ammonia and methanol are produced and consumed in many countries. Total global demand was around 170 mtpa for ammonia and around 65 mtpa for methanol in 2013. However, in comparison, international trade is relatively small at around 20-25 mtpa for each product. Hence, major exports are only from a few countries, with major consumers importing but also having their own production. With large scale export projects producing around 1 million tonnes per annum (mtpa), the internationally traded market can easily become oversupplied if a few export projects are developed at the same time. Nevertheless, demand for methanol as a transport fuel globally and fertilizer demand in Kenya is expected to increase rapidly and so these are options worth further consideration.

Though it is possible on one level to justify costly imports of LNG as gas supply for ammonia and methanol production where this is substituting more expensive naphtha, the production of ammonia and methanol really requires low cost indigenous gas production in order to be internationally competitive.

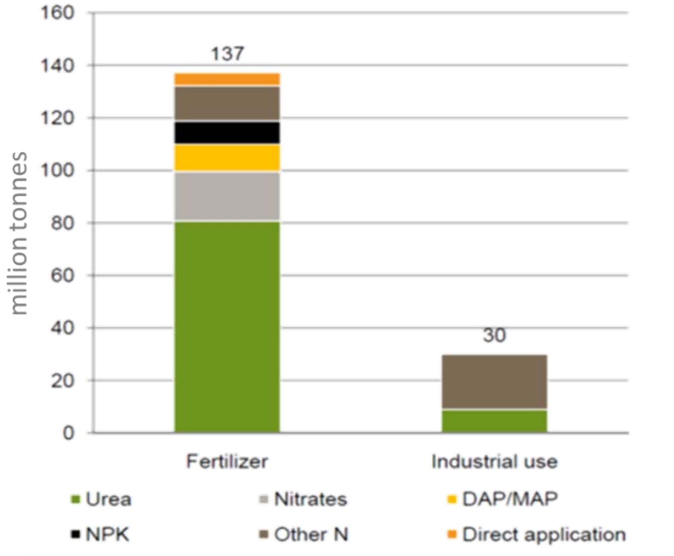
#### 7.3.3.2. Supply and demand

##### 7.3.3.2.1. Ammonia

Over 80% of ammonia produced is used in the fertilizer industry. When applied to soil as salts, solutions or anhydrously (directly), it helps provide increased yields of crops such as maize and wheat. Fertilizer products are based on Nitrogen, Phosphorous and/or Potassium compounds. All nitrogen based products (Ammonium Nitrate, Ammonium Sulphate, Calcium Ammonium Nitrate and Urea) and the key Phosphorous products (MAP (Mono Ammonium Phosphate) and DAP (Di-Ammonium Phosphate) are common with urea (ammonia reacted with carbon dioxide) prills, granules, pellets, crystals, and solutions being the most common. Other than as fertilizers, ammonia is also used in the industrial sector:

- As a source of protein in livestock feeds for farm animals
- In manufacture of nitric acid; dyes; pharmaceuticals; cosmetics; synthetic textile fibres
- Neutralising the acid constituents of crude oil
- Water and wastewater treatment
- As a refrigerant in industrial refrigeration systems found in the food, beverage, petro-chemical and cold storage industries
- For pulping wood in the pulp and paper industry

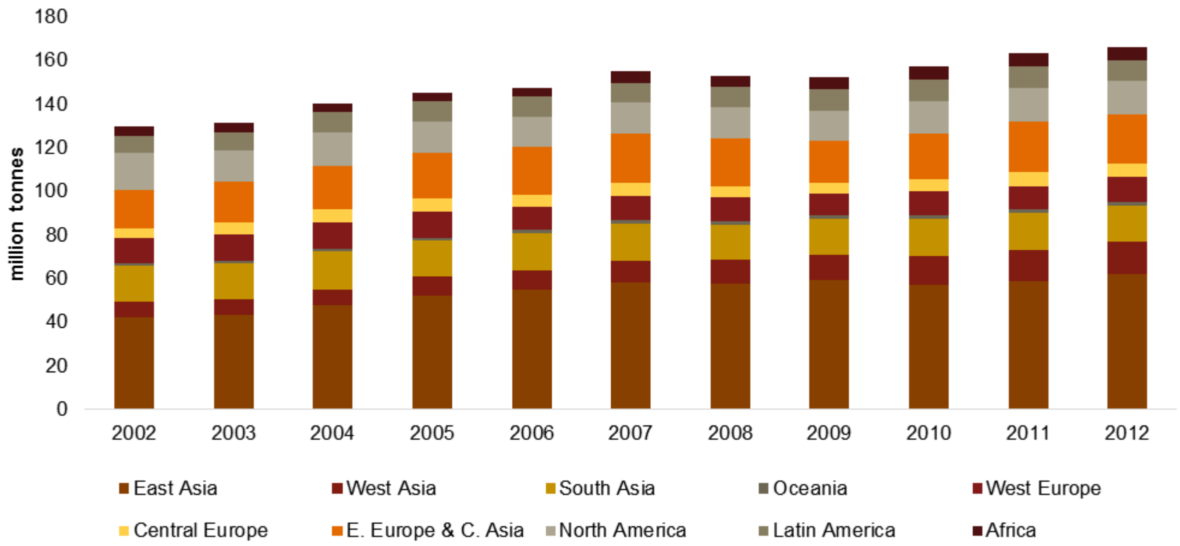
*Figure 7.14: Ammonia use in the production of different products*




*Source: Yara International*

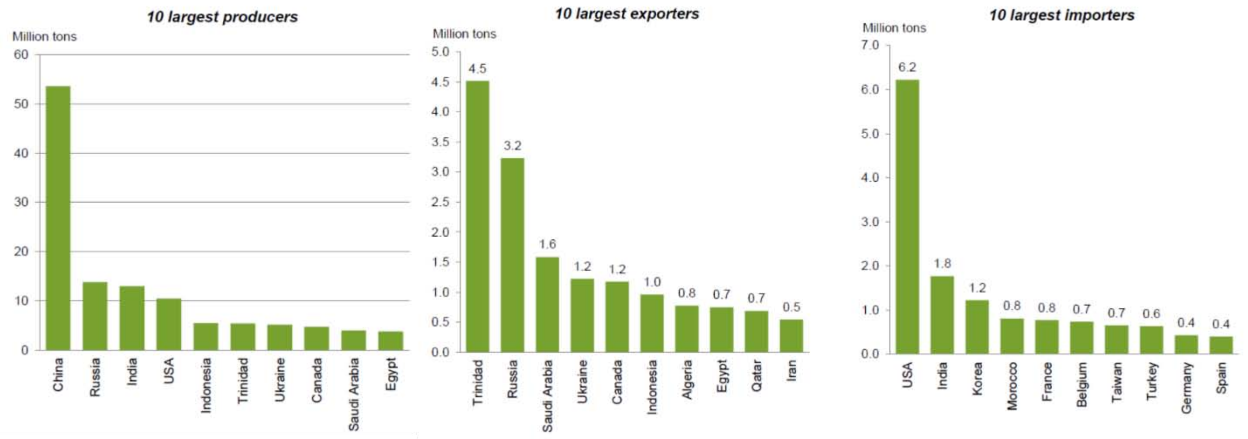
Total production of ammonia was 166 million tonnes in 2012. As shown in the chart below, the majority (close to 40%) of this was consumed in East Asia. Europe, South Asia and the US each accounted for around 12% of consumption. Total consumption in Africa was around 3.2%, equivalent to 5.3 mtpa.

*Figure 7.15: Ammonia consumptions in different regions*




*Source: IFA*

*Figure 7.16: Ammonia production and trade (based on 2012 figures)*




*Source: Yara International*

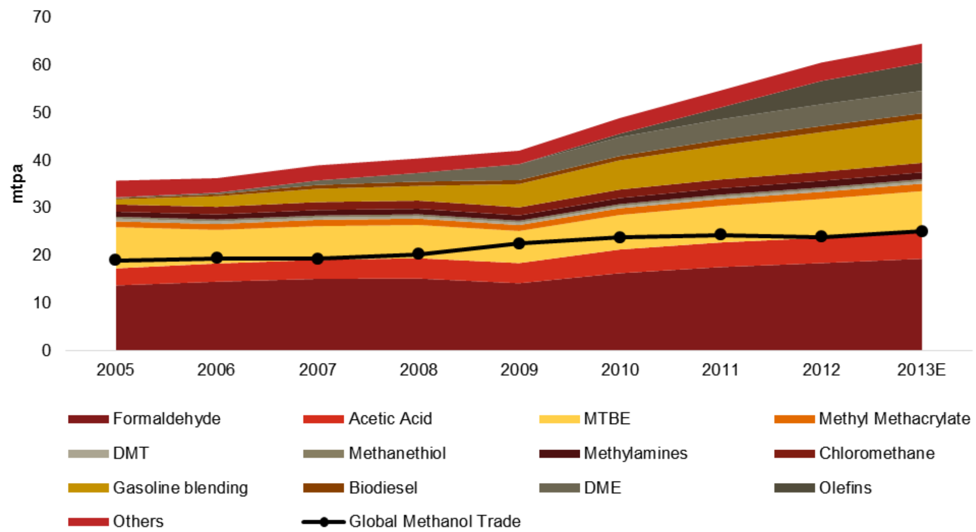
China is by far the largest producer and consumer of ammonia and makes up over 80% of consumption in East Asia. It is largely self-sufficient and has little reliance on imports. In terms of trade, less than 20 million tonnes of ammonia is traded internationally. This is just over 10% of total production. Major exporters include Trinidad, Russia and Saudi Arabia. Major importers include the US and India. Major trade routes exist between Trinidad and the US; Middle East and India; and Russia and Western Europe. Urea production and trade is similar in scale and geography to ammonia.

## *7.3.3.2.2. Methanol*

Methanol is used to produce other chemical derivatives, which in turn are used to produce everyday products, such as building materials, foams, resins, plastics, paints, polyester and a variety of health and pharmaceutical products. The primary derivatives are formaldehyde (30%), methyl tertiary butyl ether (MTBE) (13%) and acetic acid (9%). Other derivatives include manufacture of DMT, MMA, chloromethanes, methylamines, glycol methyl ethers. Demand for the production of formaldehydes is driven by the construction industry to produce adhesives for the manufacture of various construction board products.

Methanol has recently experienced rapidly growing demand in fuel applications for direct blending into gasoline (14%), dimethyl ether (DME) (7%) and biodiesel (2%). Gasoline blending applications for methanol is already common in China where it is mixed with petrol (15:85) without the need for engines to be redesigned. Methanol is also used to make MTBE, which is added to petrol in many countries to reduce 'knock'. Growth in demand for methanol for fuel applications is mainly expected to come from China.

*Figure 7.17: Global methanol consumption by derivatives*




*Source: Methanol Market Services Asia, QED*

Demand for methanol in 2013 was 65 mtpa. Many expect this to grow to over 100 million by 2025, with around 80% of the demand growth in the next decade to come from China alone. In term of international trade, Asia, and in particular China, is largely self-sufficient with a relatively small reliance on imports (from Southeast Asia and New Zealand). On the other hand, Western Europe and the US rely mainly on imports. US imports are primarily from Latin America (Trinidad, Venezuela and Chile), whereas European imports are from the Middle East (Saudi Arabia and Iran), Africa (Libya, Equatorial Guinea and Egypt) and Russia.

Despite demand expected to increase rapidly in China, with China bringing some 20 mtpa of new production capacity online in the next few years (making up 90% of total new capacity coming online) and looking to develop a further 15 mtpa of production capacity (still in planning stages), imports are not expected to match this growth in demand. Furthermore, the majority of methanol production in China currently comes from coal and most coming online will also be run using low cost, indigenous coal.

### *7.3.3.2.3. Pricing*

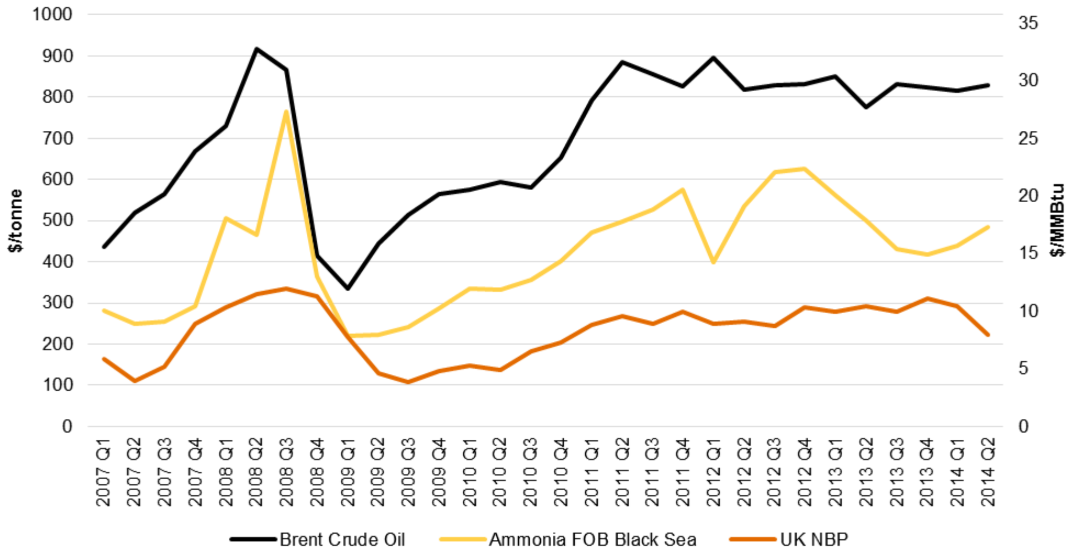
#### *7.3.3.2.3.1. Ammonia*

Ammonia is priced on a FOB basis at the Black Sea (i.e. for supply primarily from Russia) is shown in the chart below. Ammonia prices closely track crude oil and natural gas prices as gas is the largest raw material cost (around 60%-70% in Europe) and naphtha (crude oil product) is a best alternative. Russian supply determines prices in Europe and Middle East supply determines prices in India and the rest of Asia. Prices at the Black Sea are very similar to prices in Middle East given their proximity to each other.

Prices are currently over US$ 500/t, but this is expected to ease as a number of new plants start up over the next five years (including in Saudi Arabia and several in the US).

For the purposes of this Study we assume a Base Case ammonia export price of US$ 400/t at the Kenyan coast, which approximately equates to the average price since Q1 2007, and equivalent to US$ 90/bbl crude oil price (based on the historical correlation between crude oil and ammonia prices). We assume US$ 550/t and US$ 250/t as High and Low Cases respectively.

*Figure 7.18: Ammonia prices (2007-2014 Q2)*

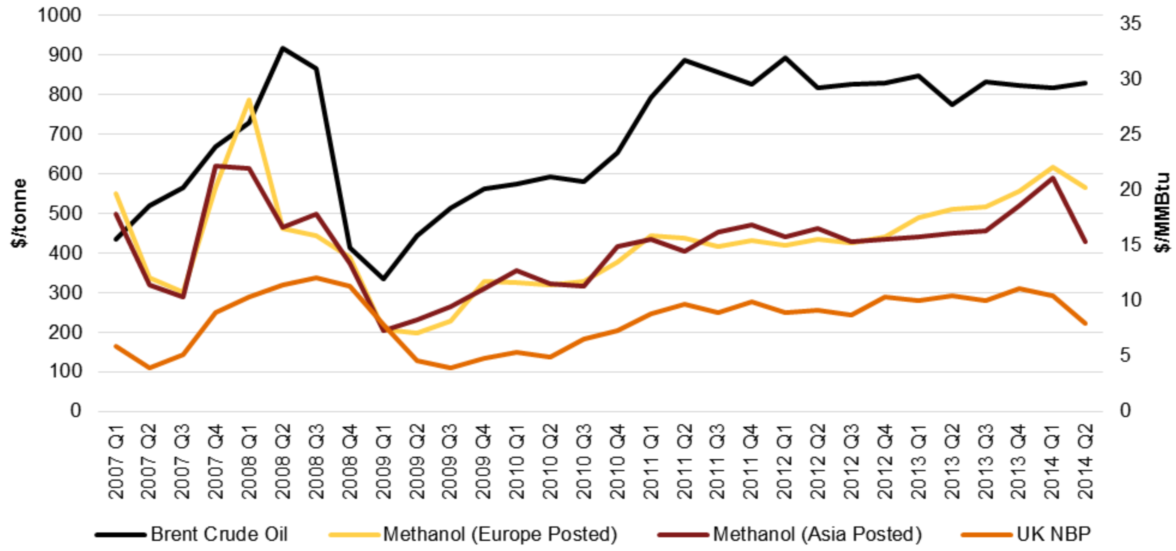



*Source: QED, Yara International*

#### *7.3.3.2.3.2. Methanol*

Methanol, like ammonia production, requires low cost gas feedstock and is therefore produced in regions with low cost gas supply (with the exception of China, which uses coal) such as the Middle East, Trinidad and in some African countries. In terms of global pricing, this is typically driven by Middle East producers seeking the optimum netback value between Chinese and European markets with some regional adjustments for short term supply/demand imbalances. Prices in the US from South American producers are set to undercut Middle East suppliers from supplying the US market. Methanex (one the largest methanol producers) posted prices (a key pricing marker) are shown in the chart below.

*Figure 7.19: Methanol prices (2007-2014 Q2)*




*Source: QED, Methanex*

For the purposes of this Study we assume a Base Case methanol export price of US$ 400/t at the Kenyan coast, which approximately equates to the average of the Methanex Posted price for Asia since Q1 2007. As with ammonia, we assume US$ 550/t and US$ 250/t as High and Low Cases respectively.

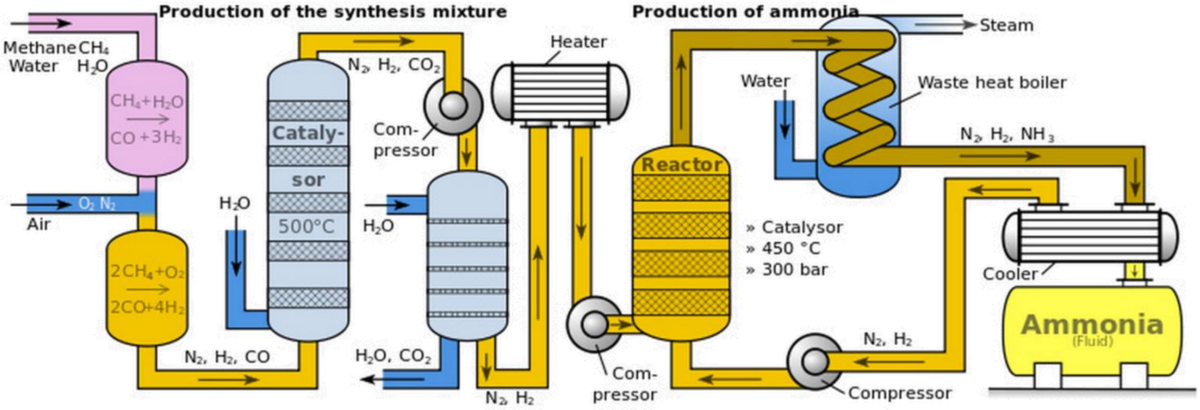
### *7.3.3.3. Ammonia and Methanol Production*

A typical modern ammonia-producing plant first converts natural gas (or naphtha) into gaseous hydrogen. The method for producing hydrogen from hydrocarbons is referred to as Steam Reforming. This is achieved in a processing device called a reformer which reacts steam at high temperature with the fossil fuels. The hydrogen is then combined with nitrogen in the presence of a catalyst (iron or ruthenium) at high pressure and temperature to produce ammonia via the Haber-Bosch process. This conversion is typically conducted at 150–250 bar and between 300–550°C. Each pass through the reactor produces approx. 15% ammonia, but recycling increases overall conversion to about 98%.

As with the first step in ammonia production, in the production of methanol natural gas (or coal) is converted into gaseous hydrogen through Steam Reforming. This is then mixed with carbon monoxide and reacted over a catalyst (a mixture of zinc, copper and alumina) at 50-100 bar and 250°C. Once pressurized and distilled it then yields pure methanol.

Approximately 20% of the gas is consumed in the production process. Hence, every tonne of ammonia or methanol produced requires 28 MMBtu or 7 GCal of gas supply.

*Figure 7.20: Haber-Bosch process for Ammonia production*




*Source: SLAS, US DoE*

## 7.3.3.4. Project scale

World scale methanol and ammonia plants are typically between 2,500 and 3,500 tonnes per day or around 0.9 to 1.25 mtpa. Ammonia and Methanol plants of this scale are currently being developed in Saudi Arabia and in the US. Several other world scale plants are being planned across Africa, including: a 2,200 t/day ammonia (and urea) plant in Gabon; a 1,725 t/day ammonia plant in Mozambique; a jointly developed methanol and ammonia project in Mozambique each with 3,000 t/day capacity; and one 3,000 t/day ammonia project and a separate 3,000 t/day methanol project in Tanzania.

As discussed earlier, total fertilizer consumption in Kenya is currently around 0.5-0.6 mtpa and is projected to increase to 1 mtpa by 2020 and to 1.4 mtpa by 2030. Hence, given strong competition in international markets and large growth in domestic demand, a plant developed in Kenya could be used to mainly meet domestic demand. We assume a world scale plant producing 3,000 t/day or several smaller plants can be developed along major gas pipeline routings inland and closer to demand centres.

In terms of methanol, as discussed in earlier, Kenyan demand is likely to be small and any mass production is likely to be exported. Hence, a methanol plant would have to be developed along the coast, forgoing any benefits of being developed alongside an ammonia plant. However, given strong competition in international markets it is difficult to consider a case for developing a methanol plant in Kenya which, like ammonia, would need access to cheaper indigenous gas resources.

In terms of gas supply requirements, a 3,000 t/day ammonia or methanol plant would require 80 MMscf per day or 0.8 Bcm per year. This is based on 28 MMBtu (or 7 GCal) of natural gas to produce 1 tonne of ammonia or methanol, and includes an assumption of 20% gas use in the production process.

## 7.3.3.5. Project costs

Given similar equipment, processes and set up, the cost for developing an ammonia and methanol plant and supporting facilities is expected to be similar. With a limited number of world scale export projects that have been developed over the last decade, we have estimated costs of developing world scale projects in Kenya based on publicly available total cost estimates for other world scale projects which are currently in the planning stages elsewhere in the Africa.

Publicly available information on project costs for projects currently being planned in Mozambique, Gabon and Tanzania are estimated to be around US$ 1b to US$ 1.5b, or US$ 1,000 per tonne per annum (tpa) to US$ 1,500/tpa, for the development of a 1 mtpa ammonia or a 1 mtpa methanol export project. These projects are, however, still in early stages of planning and therefore more accurate figures are not yet reported.

However, project cost estimates of between US$ 750-1,100/tpa are in line with the capital costs reported for other greenfield projects which are currently under construction and expected on line in the near future. These include:

| Developer | Location | Start-up | Capacity (mtpa) | Estimated total cost ($m) | Estimated total cost ($/tpa) |
|---|---|---|---|---|---|
| Incitec Pivot Ltd[21] | Louisiana, US | Q3 2016 | 0.8 | 850 | 1,063 |
| Ma'aden[22] | Saudi Arabia | Late 2016 | 1.1 | 825 | 750 |

Hence, for a project in Kenya, we assume the cost for the development of a 1 mtpa ammonia or methanol project will be approximately US$ 1b in the Base Case. In the High Cost and Low Cost Case we assume capital costs will be US$ 1.5b and US$ 0.75b respectively. Project costs would of course differ based on project specific factors, but these should be covered within the ranges of our low and high cost scenarios.

In terms of operating costs (cash costs at site level), the main elements are:

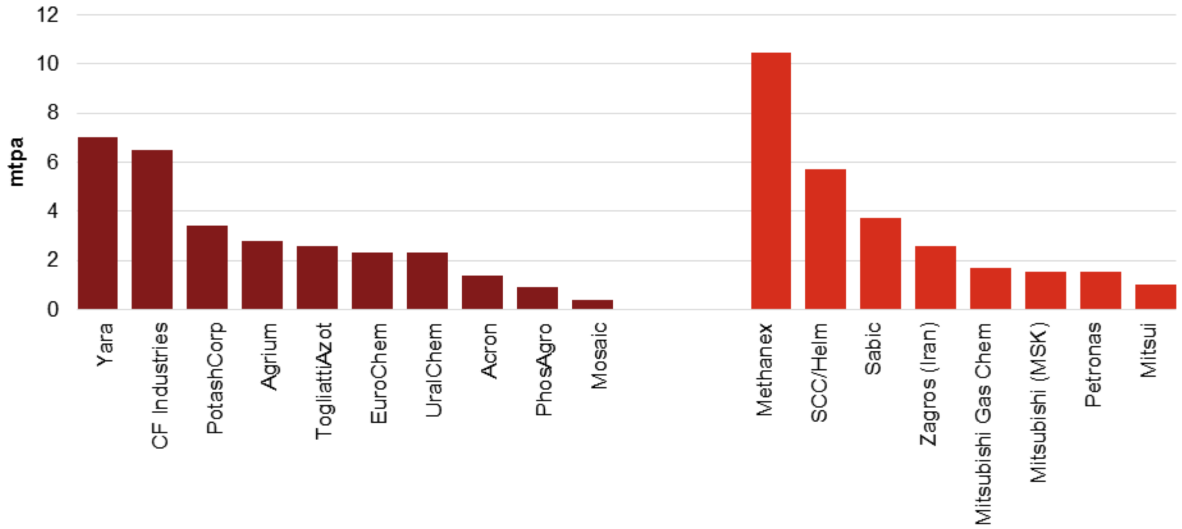
- Fuel gas consumption: estimated to be 20%, valued at the netted back methanol/ammonia price
- Maintenance cost: estimated as 1% of the capital cost each year
- Labour costs: relatively low given number of staff required to run the plant
- Variable Opex: Electric power (30kWh/t), cooling water (free - seawater), catalysts and chemicals (US$ 1/t)
- Local and national taxes

In general, total annual operating costs can be estimated to be approximately 5% of the total capital cost (excluding fuel gas). This is also consistent with the magnitude of operating costs reported for new projects based in the US.

## *7.3.3.6. Players and options for Government or NOC participation*

Some of the world's largest methanol and ammonia suppliers by market share are shown in the chart below. As can be seen, players are typically petrochemical and fertiliser suppliers as opposed to oil and gas companies (with the exception of Petronas). Most of these players are either publicly listed or privately owned (in the case of projects in Russia). State ownership is only in the case of Sabic (70% Saudi Govt) and Zagros (50% Iranian Govt).

*Figure 7.21: Largest methanol and ammonia merchant players*




*Source: Methanex (2013 data), EuroChem (2012 data)*

[21] http://www.incitecpivot.com.au/about-us/major-projects/ammonia-plant-usa
[22] http://www.maaden.com.sa/en/news_details/109

These players mainly own and operate their own ammonia and methanol plants. Government participation in projects is small. The exceptions being:

(i) in Trinidad, where the Government was a major shareholder in some of the earlier ammonia projects, although it has not opted for shares in newer developments;
(ii) in Equatorial Guinea, where the national gas company, Sonagas, is a 10% shareholder in a methanol project with Marathon and Noble Energy (who are mainly oil and gas players) with the remaining shares.

For other projects that are currently being planned in Africa:

(i) in Gabon, along with Tata Chemicals, the Government is a minority shareholder in the fertiliser project with OLAM holding majority of the shares;
(ii) in Tanzania, where the fertilizer project is being developed by Korean Huchems Fine Chemicals along with Gro Energy (agriculture player) and Infotech Investments Group (private investors), and an ammonia plant is being planned by a group of independent oil and gas players as the best option for monetising their gas reserves, with neither project including Government involvement as yet; and,
(iii) in Mozambique, where an ammonia plant is being planned by Toyo and Sumitomo and the other joint methanol and ammonia project is planned by Helm and Proman, with a proposed minority interest being held by the national gas company (ENH).

In summary, Government participation in ammonia and methanol projects is not common. This may be due to the complexities of marketing the finished products and the relatively low rates of return typically made by the plant. Where the Government may have a larger role to play, as in the case of Trinidad, is in supply of gas to such projects through the state-owned gas company.

## 7.3.4. Gas use in industry

### 7.3.4.1. Background

The industrial sector can represent a major gas demand centre. The industries that are most relevant in terms of requiring large energy requirements include the production of chemicals, metals, ceramics, rubber, paper, glass, cement and food. Natural gas demand across these industries differs depending on how the gas is used. These can be categorised as follows:

- **As a feedstock**, to make chemical products, methanol, ammonia and fertilizers (as discussed separately in more detail earlier in this section), plastics, and other materials.
- **In process heating**, which is the production of heat directly from fuel sources and electricity and applied to raw material inputs during manufacturing – common in glass melting, metal melting (mainly aluminium and steel), preheating and drying (ceramics). Process heating also includes the use of gas as a fuel in boilers to produce heat and steam during manufacturing – common in food processors and pulp and paper production.
- **As a fuel for on-site heat and electricity generation**, in Combined Heat and Power (CHP) plants, which can be more efficient than buying power from the grid depending on transmission losses.

Gas consumption in these different forms will also vary across countries. For example, countries with large gas pipeline distribution networks will tend to consume more gas in process heating and as a fuel for boilers. Those with less demand for process heating or with less developed gas supply networks will tend to use gas in feedstock in large scale manufacturing, where products are usually then exported. Use of gas in CHPs is also somewhat limited in the absence of a regional gas network given the scale of CHPs, which can be less than 10MW in capacity.

Some key examples of natural gas in process heating are provided below:

- Ceramics: Ceramic products include homogeneous to glazed tiles for the building industry such as wall tiles, floor tiles and roof tiles. Ceramic products are formed from clay or similar substances in the plastic state, which is dried and heated at a sufficiently high temperature to provide the necessary strength. Natural gas is mainly used for powder drying, tiles drying and final heat treatment.
- Glass: In the glass industry, cullet and silica are heated into molten glass and subsequently put through various heating processes resulting in an end product. Natural gas is used in the various processes such as melting, refining, fabricating, annealing, fiberizing and baking.
- Steel: Steel melting is achieved by means of striking an electric arc between graphite electrodes and the charge. Natural gas / Oxygen burners are used for supplementary firing in this process. It produces a high flame temperature to preheat the raw material and maintain molten steel temperature.

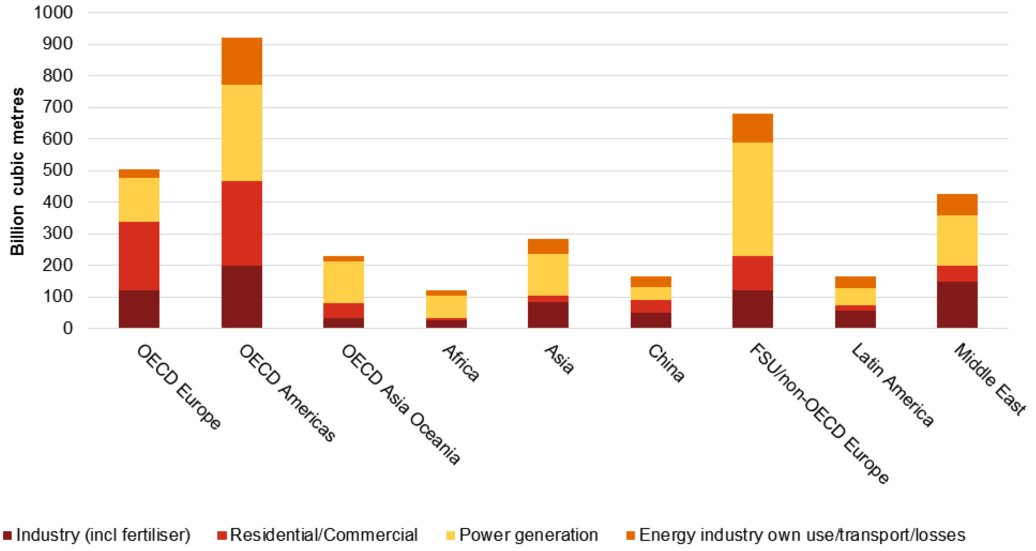
Natural gas competes with coal and oil products as a fuel in the above mentioned industrial processes. Heat can typically be produced more cheaply in large scale industrial processes requiring constant heat through burning coal, with oil products and gas used in more variable processes and where precision is required. Gasoil (also known as Diesel) tend to be used where natural gas is not readily available. Fuel oil is also an option and is common in other countries with less stringent pollution and environmental laws. Where clean burning heat is required or where fuel is used as a feedstock (for hydrogen production), natural gas competes with oil products like naphtha and gasoil.

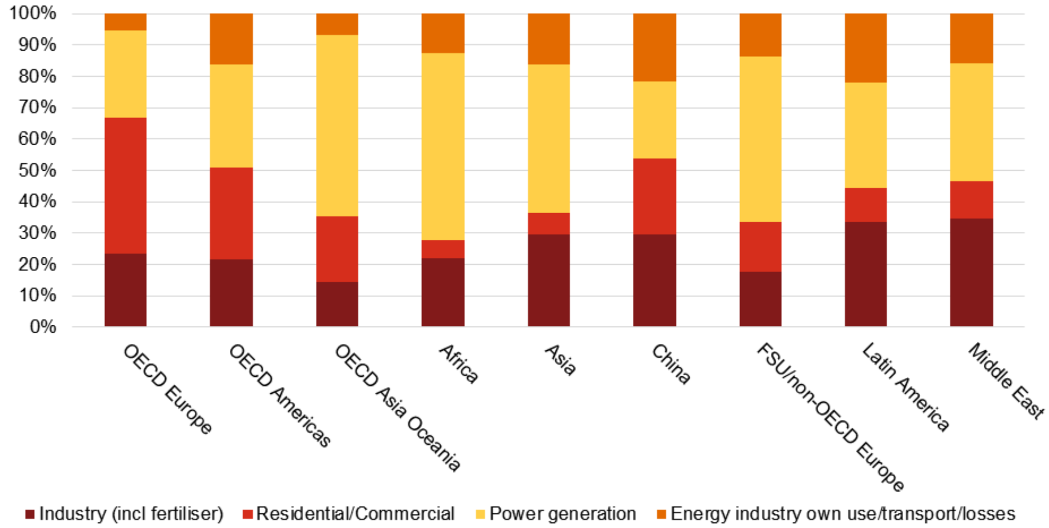
In the US and in Europe, the use of natural gas in industry has increased rapidly over the last two decades. More countries are now also turning to natural gas use in industry as it tends to be cheaper than oil products (particularly given the sharp increases in crude oil prices over the last decade) and cleaner than coal. In countries like India, gas supply through imports of LNG is still competitive for petrochemicals and fertilizer production, rapidly replacing naphtha.

## 7.3.4.1.1. Supply, demand and pricing

Natural gas use in industry forms approximately 20-30% of total gas consumption in most regions around the world, as shown in the charts below. In Africa, gas use in industry is 26 Bcm/yr, and is likely to be mainly as feedstock in large scale fertilizer and methanol projects in gas rich countries like Nigeria, Egypt and Algeria.

*Figure 7.22: Industrial gas demand as proportion of total demand (2013)*

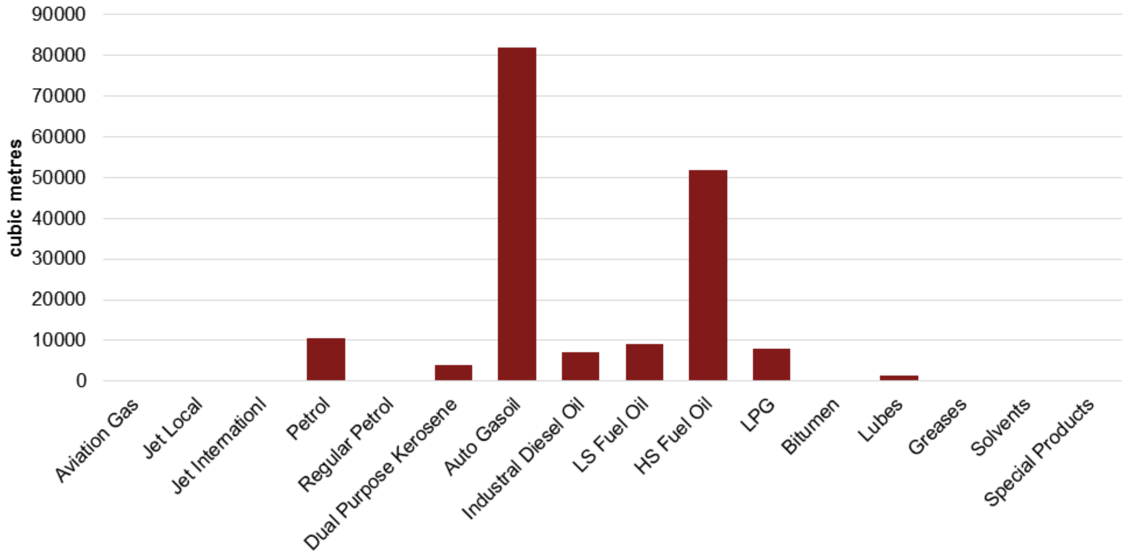



*Source: IEA, QED*

In Kenya, even though gas use is zero, some manufacturing of the above mentioned goods/products (glass, ceramics, paper) is expected. In the absence of gas, oil products are most likely to be used in manufacturing to provide feedstock, process heating and on-site combined heat and power generation. As shown in the chart below, the main oil products consumed in the Manufacturing sector are gasoil and fuel oil. Majority of gasoil is expected to be consumed as a fuel in transport (i.e. Diesel), leaving fuel oil as the key fuel, likely to be used in industrial boilers to provide heat and steam. Industrial Diesel Oil (Industrial Gasoil) may be used as feedstock, but is relatively small.

*Figure 7.23: Fuel consumption in the manufacturing sector in Kenya (2013)*




*Source: Petroleum Institute of East Africa*

The Manufacturing sector in Kenya currently only accounts for 4% of total oil products consumption (with Aviation (15%), Retail outlets (39%) and Resellers (distribution to small agriculture, commercial and industrial) (29%), making up the largest shares). Specifically on High Sulphur (HS) Fuel Oil, 17% is consumed in Manufacturing, 10% in Mining, 19% in Power Generation, and 46% in Other Commercial Sectors. Though not shown in the chart above, coal can also be expected to compete with fuel oil for use in boilers to provide heat and steam.

### *7.3.4.1.2. Pricing*

As discussed above, in Kenya natural gas will have to compete with oil products in the manufacturing sector. Below we provide a high level view of oil product prices in Kenya and compare this to options for domestic gas pricing in Kenya for the manufacturing/industrial sector and then also compare gas prices to the industrial sector in other countries around the world.

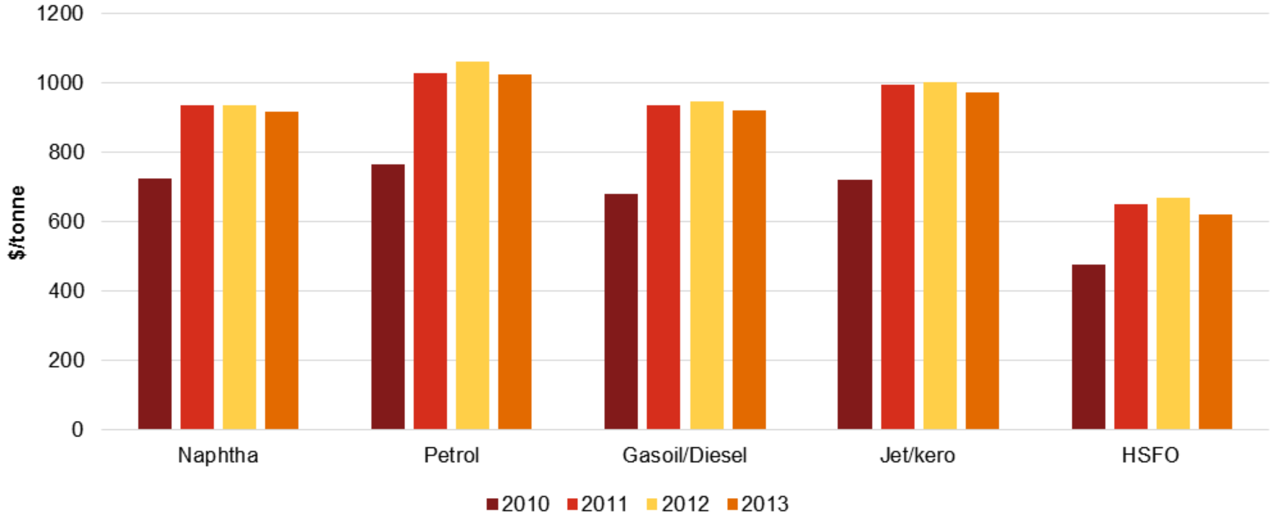
Petroleum products are imported into Kenya by several players on a competitive basis, with prices likely to be determined by cost of purchase and transport to Kenya. We have used the reported FOB Arab Gulf price for the different products and assumed a cost of freight to Mombasa to get an estimate for the delivered price at Mombasa. Freight assumptions are as follows:

*Table 7.7: Freight pricing assumptions*

| US$/t | naphtha | Petrol | Gasoil/Diesel | Jet/Kero | HS Fuel Oil |
|---|---|---|---|---|---|
| Freight Arab Gulf - Mombasa | 29 | 32 | 26 | 29 | 20 |

A margin for the supplier would also be included in the cost of supply but, this can vary depending on market conditions and across different products. Margins for competitive supply are typically less than US$ 10/t and have not been included in the analysis. Prices for delivered oil products to Mombasa from the Arab Gulf are shown below.

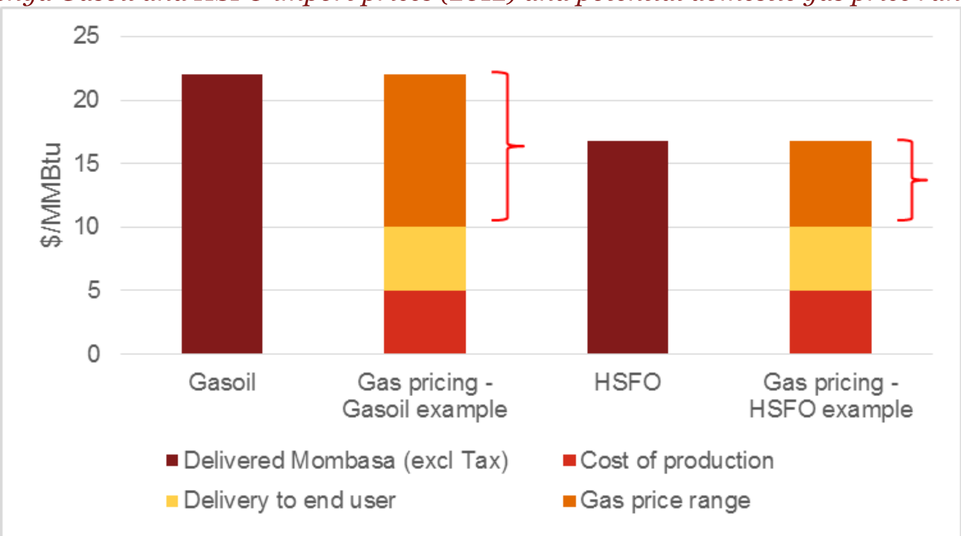
*Figure 7.24: Estimated oil product import prices, DES Mombasa*




*Source: Argus, QED*

Prices for Naphtha, Gasoil/Diesel and High Sulphur Fuel Oil (HSFO), excluding taxes, are then converted into US$/MMBtu (assuming conversion rates of 45.5, 43, 40 MMBtu/t for Naphtha, Gasoil/Diesel and HSFO, respectively) and compared to high level estimates for the cost of gas production and gas supply to end users, to provide an indication of potential ranges of gas pricing to the manufacturing/industrial sector in Kenya. The basis for the gas pricing assumes: 1) a minimum gas price equivalent to the cost of supplying gas to the end user; and, 2) a maximum gas price equivalent to the cost of the next best alternative to gas (Gasoil or Naptha as feedstock and Gasoil or HSFO for heating). The results are shown below, where the price for domestic gas supply in Kenya can potentially range between US$ 10-22/MMBtu.

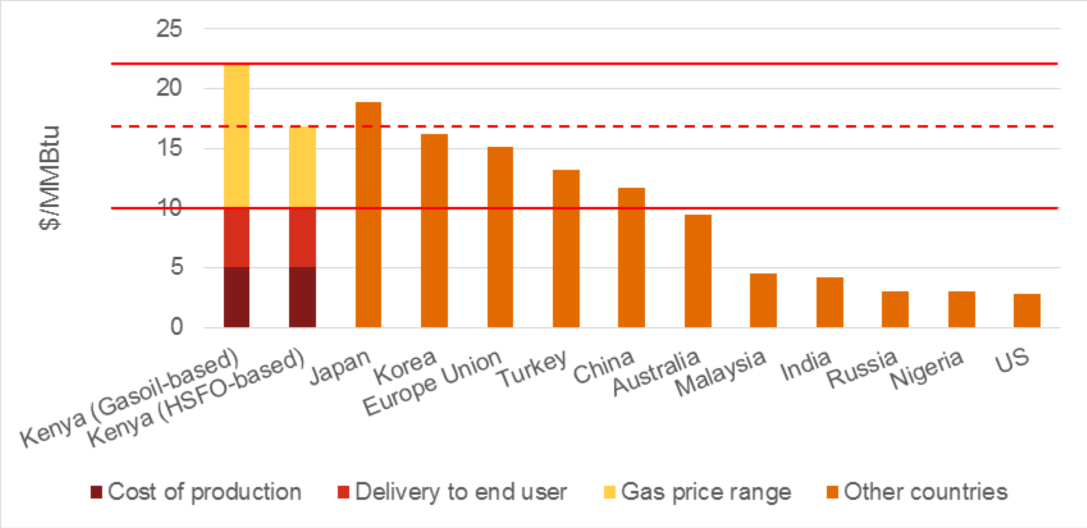
*Figure 7.25: Kenya Gasoil and HSFO import prices (2012) and potential domestic gas price range*




*Source: QED*

In theory, prices could be even higher as oil products are usually taxed (whereas gas is not), and the cost of oil distribution have been excluded. In practice, gas is usually much cheaper than oil products as is shown below in the comparison of average gas prices (2012 data) to large industry in a selection of countries.

*Figure 7.26: Potential gas prices to the industrial sector in Kenya and elsewhere (2012)*




*Source: IEA, QED*

In the developed gas markets of Japan, Korea, EU and Turkey, gas is priced on the cost of supply/cost of gas imports, with competition between many gas suppliers. In most markets, the cost of gas imports is linked to the price of oil through contract indexation. Hence, gas prices track the oil product prices which it competes against in the different sectors, albeit at a lower level, reflecting the lower commodity cost of gas and lower applicable taxes. The North West European and US markets, with liquidly traded gas markets and significant indigenous gas production, operate differently. Traded gas prices, and not the cost of imports or the cost of alternatives fuels, determine prices to end users. The US has recently started producing significant amount of shale gas and is currently oversupplied, which has led to a crash in traded gas prices and hence in prices to end users.

In India, Malaysia, Russia and Nigeria, gas prices are heavily subsidised. This has not served as a sustainable model and, despite encouraging use, it has not allowed for the development of the domestic market in terms of supply infrastructure (e.g. in Nigeria) and/or indigenous gas production (e.g. in India). Malaysia and Russia are some of the world's largest gas exporters. Subsidising gas has led to large budget deficits, and both countries are expecting to increase domestic prices up to export parity levels. However, this is difficult to implement without a backlash from consumers after a long period of subsidies.

In Kenya, even with its potentially large indigenous gas production, the lack of demand and a traded gas market (which requires competition between many suppliers and buyers and an extensive gas supply network) means gas pricing is likely to be set in order to cover the costs of supply and to allow users to invest in new appliances/boilers and economically switch from using more expensive oil products on a sustained basis.

## *7.3.4.2. Project scale*

Unlike the other larger scale gas monetisation options, project scale for industrial manufacturing plants/sites varies considerably. Scale can depend on many different aspects, but it is not typical for a given manufacturing plant or site to be larger in terms of gas consumption than a gas-fired power plant or an ammonia or methanol export plant.

In developed gas markets, with extensive gas networks, manufacturing plants/sites that rely on gas supply year round for the manufacture of the products discussed earlier (glass, ceramics, metals etc.), can be developed in many different places as connection to an extensive grid is more affordable and relatively easy to do.

In order to give an idea of the scale of typical manufacturing plants/sites in terms of gas consumption, we have taken examples of actual gas demand from plants/sites that are directly connected to the gas transmission network in the UK. As can be seen, although these are some of the largest manufacturing plants in the world, demand is typically smaller than for gas-fired power generation (0.7 Bcm/yr for an 800MW plant) or for ammonia/methanol production (1 Bcm/yr for a 3,000t/day plant). In total there are around 20 such industrial/manufacturing sites directly connected to the transmission grid in the UK, but many more connected to smaller pipeline distribution (low pressure) networks. Some examples (non-ammonia/methanol, which typically consume much less than 0.5 Bcm/yr) are shown below.

*Table 7.8: Gas demand for major industrial/manufacturing plants/sites in the UK*

| | | | Bcm/yr | | |
|---|---|---|---|---|---|
| **Company** | **Manufacturing** | **Location** | **2011/12** | **2012/13** | **2013/14** |
| | Glass | Goole | 0.04 | 0.05 | 0.05 |
| UPM Shotton | Paper | Shotton | 0.05 | - | - |
| Imperial Chemicals Industries | Chemicals | Runcorn | 0.12 | 0.08 | 0.03 |
| Murco | Chemicals | Teesside | 0.18 | 0.16 | 0.12 |
| E.ON | Steam + CHP | Northwich | 0.64 | 0.33 | 0.21 |
| BASF | Various | Cheshire | 0.16 | 0.17 | 0.13 |
| BOC | Industrial gases | Teesside | 0.12 | 0.11 | 0.13 |
| BP/INEOS | Chemicals | Salt End | 0.13 | 0.15 | 0.12 |

*Source: National Grid, QED*

Comments:

- E.ON production of chemicals includes: Soda ash; sodium bicarbonate; calcium chloride; associated alkaline chemicals.
- BP/INEOS production of chemicals includes: 600,000 tonnes of acetic acid per year, and about 150,000 tonnes of acetic anhydride per year (the largest manufacturer in Europe), vinyl acetate monomer (VAM) – which is used in paints, adhesives, floor coverings and clothing.
- BOC production of industrial gases includes: hydrogen, oxygen, nitrogen and argon, supplied by pipeline to other companies
- BASF production of various products includes: polyurethane systems; industrial coatings; pigments; products used to enhance industrial processing in various industries such as papermaking, mining, oil extraction, wastewater treatment and textile processing.
- UPM Shotton is the UK's biggest recycler of newspapers and magazines. UPM Shotton recycles approximately 640,000 tonnes of recovered paper per year.

### 7.3.4.3. Players and options for Government or NOC participation

In Kenya, as with many other countries with new gas industries, such plants/sites can only be economically developed close to larger anchor projects, with the anchor projects justifying the construction of a trunkline gas pipeline bringing gas to the area. The unit cost of gas transport to a small user would otherwise be too costly, inflating the overall gas price.

Hence, the use of gas in manufacturing/industrial sector in Kenya is likely to be limited to new industrial parks developed along trunkline gas pipeline routes supplying large scale anchor projects, expected to be mainly large gas-fired power plants, or adjacent to these anchor projects. Anchor projects consume a sufficiently large volume of gas to enable the unit cost of transportation to represent only a small portion of the overall delivered cost of the gas.

Spur lines off the main trunkline can then be developed to supply industrial parks along the route where a number of industrial users/manufacturing plants can be located, with sufficiently high demand to justify the costs of developing the spur line (and possibly a portion of the trunkline, depending on what is agreed by the developers of large anchor projects, industrial users and the Government).

This is not to say that any cross-subsidisation between large and smaller consumers would be required, simply that the volume throughput for the larger users will ensure that all users can benefit from the associated economies of scale. Government intervention may be required for planning and developing large anchor projects, and to encourage the development of industrial parks around/nearby anchor projects. The developers of anchor projects may require long term concessions (e.g. derogation from subsequent market regulatory change for a period of time) in order to accept the risks involved.

## 7.3.5. LNG export projects

### 7.3.5.1. Background

LNG provides a method of transporting gas across long distances by sea. It is not a product in its own right, but a sub-set of the gas business and in many markets it has to compete with gas delivered by pipeline. The lack of gas pipeline supply options in Asia means buyers are willing to pay a premium to secure supply. LNG plants are highly capital intensive with the majority of the investment being made upfront. This means that project lenders require assurance on a reliable stream of cash flows up until the loans are repaid. Historically, this has been achieved by selling nearly all the LNG to buyers under long term (15-20 year) contracts with prices indexed against international crude oil prices. LNG sales to liquid gas markets in the US and in Europe prove more difficult as prices are determined by regional supply and demand fundamentals and until very recently have been well below oil indexed levels. In recent years, the emergence of a number of portfolio players (i.e. companies capable of entering into large volume, long term commitments with liquefaction projects on the strength of their own balance sheets with a view to selling the LNG in different sized parcels to end users) has increased the liquidity of the LNG traded market and facilitated further investment in the LNG supply chain.

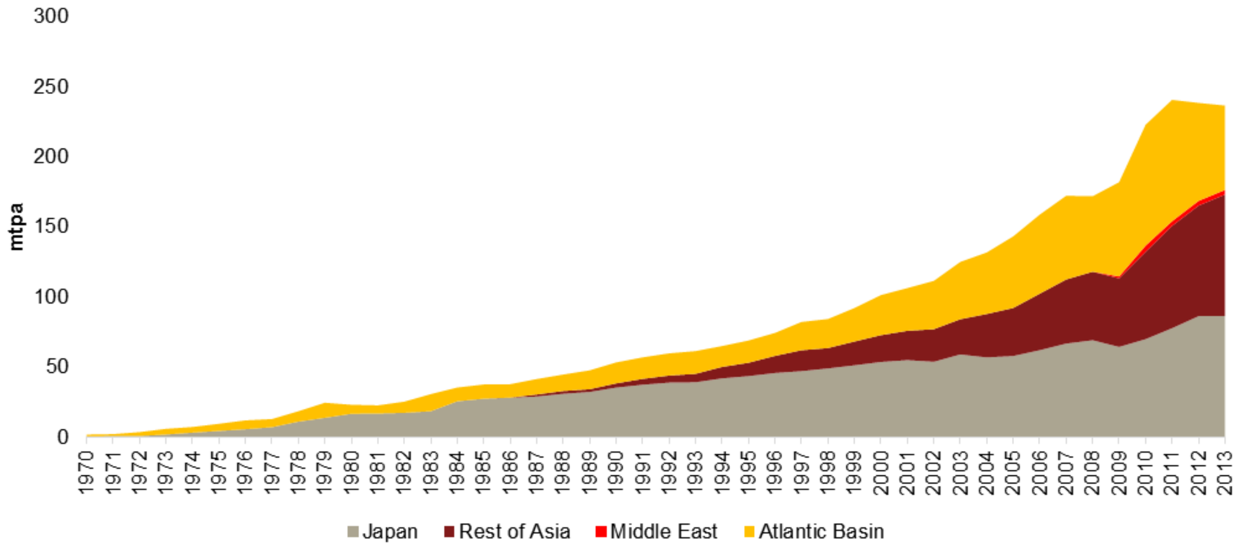
#### 7.3.5.1.1. Supply and demand

The global LNG market can usefully be considered to consist of two main regional markets or basins: Asia Pacific (Asia) and the Atlantic Basin (Europe, South America and North America). A timeline for the development of the LNG industry in terms of major new production facilities is shown below:

- 1964: First commercial LNG production from the CAMEL plant in Algeria with supply to the UK initially and then France once UK discovered gas in the North Sea.
- Late 1960s-Early 1970s: Algeria developed additional plants as did Libya to supply Spain, Italy, France and the US. Conoco Phillips developed the Kenai plant in Alaska. Brunei, Indonesia and Abu Dhabi also started developing plants in partnership with Japanese buyers for the Japanese market.
- Through the 1980s: Indonesia and Malaysia continued to develop additional LNG plants. Australia develops its first LNG plant.
- Late 1990s: Nigeria, Trinidad and Qatar bring first LNG projects online anchored to the Atlantic Basin (mainly US and UK) markets.
- Early-late 2000s: Malaysia, Australia, Nigeria and Trinidad expand existing projects to include additional trains. Qatar brings RasGas II online and Australia's second LNG project (Darwin LNG) starts up. Egypt sees first LNG production from two LNG projects. Norway, Oman and Equatorial Guinea bring new LNG projects online.
- 2009-2011: 8 new projects come online – Tangguh (Indonesia), Sakhalin (Russia), Qatargas 2 & 3 &4 and RasGas III (Qatar), Peru LNG and Yemen LNG.
- Since 2011: Australia's third LNG project (Pluto LNG) and Angola LNG come online and very recently Papua New Guinea LNG.

There are currently around 70 LNG projects in operation worldwide and total volumes produced and traded amounts to approximately 285 million tonnes per annum (mtpa).

*Figure 7.27: Growth of the LNG trade*




*Source: QED Analysis*

*Table 7.9: LNG production capacity by region*

| Mtpa | Operating | Under Construction | Planned | Total |
|---|---|---|---|---|
| **Asia Pacific Basin** | 113.5 | 64.6 | 145.5 | **323.6** |
| **Middle East** | 100.6 | 0 | 53.9 | **154.5** |
| **Atlantic Basin** | 79 | 34.5 | 199.9 | **313.4** |
| **Total** | **293.1** | **99.1** | **399.3** | **791.5** |

*Source: PwC Consortium Analysis, as at September 2014*

Qatar is currently the largest exporter of LNG in the world with nameplate export capacity of 77 mtpa, followed by Indonesia with just under 40 mtpa. However, with 7 projects currently under construction (expected to come online before 2017) and with around 24 mtpa currently in operation, Australia is expected to overtake Qatar as the leading exporter.

As shown in the above table, there are ten LNG export projects currently under construction, most of which are expected to come online in the next few years and the remaining expected to come online before 2020. Production capacity is expected to increase by 36% to around 400 mtpa before 2020. Nearly all of this additional capacity has already been sold under long term contracts prior to taking Final Investment Decision (FID) and beginning construction, as a prerequisite for financing the project to buyers in Japan, Korea, Taiwan, India and China.

However, there is another 400 mtpa of production capacity that is in the planning stage, yet to take FID. New greenfield projects are being planned in Russia, Nigeria, Israel, Canada, Mozambique and Tanzania. Brownfield, expansion and floating LNG (FLNG) projects are currently being planned in Nigeria, Australia and in the US.

The US and Canadian markets have attracted considerable interest since 2009. With significant increases in shale gas and shale oil (with further shale gas as by-product) production, North American gas prices have collapsed and remained low (<$4/MMBtu). The oversupply has led to diversions of LNG supplies originally developed to supply the US to other markets, with LNG now only being supplied to the US North East region and mainly in winter periods. Low gas prices have also prompted LNG import terminal owners to seek Government approval for the conversion of their terminals into LNG export projects. With common infrastructure already in place (e.g. storage tanks, jetty), major investment required would mainly be for the liquefaction units. LNG export projects would source the gas from the highly liquidly traded US market at market prices which have been driven down close to the cost of production given the oversupply situation –

with shale oil (and associated gas) production now contributing more to the oversupply position. Hence, with gas market prices at similar levels to costs of gas production in other countries with planned LNG projects, and with cheaper costs of production, the US is set to become a major LNG exporter. As discussed below, the US has 13 LNG import terminals in operation. Five of these terminals have already received export approval and are under construction or close to taking Final Investment Decision having secured LNG buyers or liquefaction capacity holders under long term contracts (>10 years). More than ten other projects, including greenfield projects (i.e. not based on conversions of existing terminals) are in the planning stages and awaiting Government approval and some of these have signed preliminary agreements with buyers.

There is a lot of competition between planned projects globally for securing affordable resources and access to market. Given the high capital costs involved, lenders are only prepared to finance a project if offtake has been secured under long term (15-20 year) contracts. There are several other project or country specific challenges each of the planned projects face. This will mean that not all projects will be developed at the same time and some may not be realised at all. Nevertheless, given the 4-5 year construction period, none of the greenfield projects are expected online before 2020 and only some of the brownfield projects (mainly US conversions of LNG import terminals) may come online before then.

As mentioned above, Spain, Italy, France, Japan and the US were the first countries to develop major LNG import capacity. By the end of 1990, Japan had a total of 15 terminals in operation, Spain and the US had 3 each, France had 2 and Italy, Taiwan, South Korea and Belgium had one each.

Between 1991 and 2004, Japan developed another 11 terminals, South Korea another two terminals and USA, Spain each developed one more terminal. Turkey, Greece, Puerto Rico, Dominican Republic, Portugal and India also developed their first import terminals.

Over the last decade (2005-2014) many more countries have built LNG receiving terminals. In total there were 60 terminals developed in this period. Many of these were additions to the capacities of existing importing countries but there were also terminals coming online in new LNG destinations such as 9 in China, 3 in Mexico, 4 in the UK and 6 terminals in South America. Thailand, Indonesia, Malaysia and Singapore also each developed an import terminal.

The reasons why these countries developed LNG import terminals varies but included: diversification of gas supply; replacement of depleting indigenous production; replacement of oil and coal and meeting the growing demand in power generation, and meeting growing gas demand for use in industrial and residential sectors. In addition, many countries, particularly in Asia, have few options on pipeline gas supply and hence have to rely on LNG.

*Table 7.10: LNG import terminals by region*

| | In Operation | Under Construction |
|---|---|---|
| **NW Europe (FR, BE, UK, NL, PL, LI)** | 9 | 4 |
| **S Europe (SP, IT, PT, GR, TR, MA)** | 12 | 4 |
| **USA** | 13 | 0 |
| **Other N America** | 5 | 0 |
| **S America (BZ, AR, CL, UR)** | 6 | 1 |
| **China** | 9 | 5 |
| **India** | 4 | 0 |
| **Japan** | 34 | 4 |
| **S Korea** | 4 | 2 |
| **Taiwan** | 2 | 0 |
| **Other Asia (SG, TH, IN, ML, PH, PK)** | 5: | 3 |
| **Middle East (UAE, KW, JD)** | 2 | 1 |

*Source: QED Analysis*

There are currently around 100 LNG terminals in operation worldwide, 24 under construction expected to come online within the next few years, and many more (>100) in the planning stage, although many of these will compete with others to be finally developed.

### *7.3.5.1.2. Pricing*

The North American and NW Europe gas markets are fully liberalised whereby gas prices are determined at notional traded hubs as well as on financial exchanges, and are driven by gas supply and demand fundamentals. Henry Hub near Louisiana on the Gulf Coast is the main hub in the US against which LNG imports are priced. More recently, large shale oil and gas plays has led to oversupply in the US and a sustained drop in natural gas prices (as shown in the chart below) with the major players and the owners of LNG import terminals looking to convert these facilities into LNG export projects. With the US turning from a major LNG importer into a major LNG exporter, Henry Hub has now become the basis for pricing exports from the US, where the LNG export price (FOB) is the Henry Hub price plus a fixed cost to cover (primarily) liquefaction costs (US$ 3-4/MMBtu). Given lower demand for imports, LNG imports are now mainly into the New England region.

LNG imports into NW Europe are also priced against traded hub prices, the main ones being the NBP in the UK, TTF in Netherlands, and Zeebrugge in Belgium. In NW Europe all hub prices are fully converged with differentials largely limited to the cost of transport between the hubs. Pipeline gas imports are also increasingly being indexed to these hub prices replacing the historical norm of indexation to oil product prices. However, in Southern Europe (Spain, Italy, Portugal, Greece, Turkey), where there are less liquidly traded gas markets, indexation to oil products and to crude oil is still common practice.

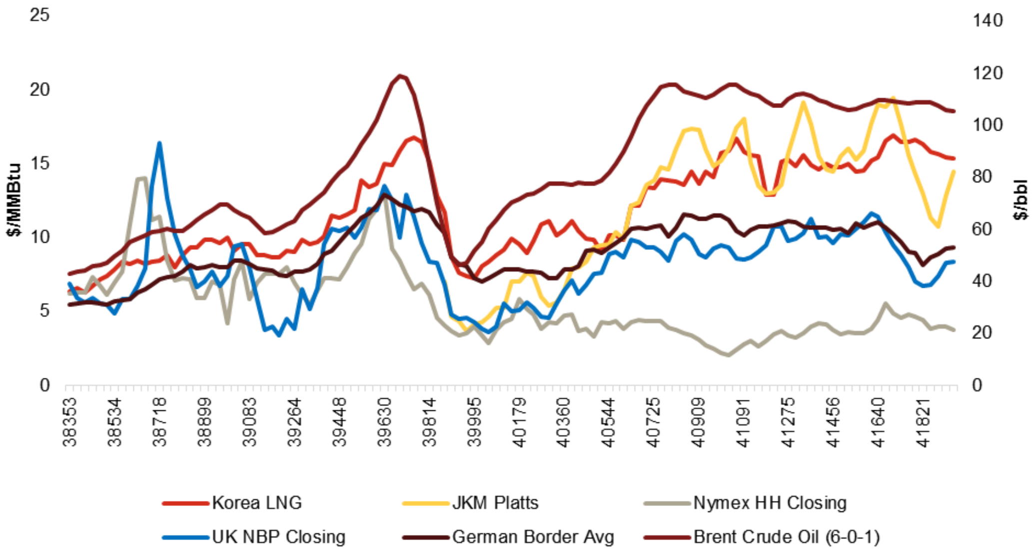
For Kenya, given its location, any LNG exports are more likely to be targeted to premium paying markets in Asia. As outlined above, unlike the US and Europe, these markets have to rely on LNG to a much greater extent due to a lack of indigenous supply or pipeline imports.

At present, the vast majority of LNG supply to Asia is sold under long term contracts and indexed to crude oil prices. The level of indexation to crude oil differs by contract ranging between 6% and 16% depending on when the deal was struck (i.e. in a buyer's or seller's market) and under what other terms and conditions. The average LNG price into Japan, Korea and Taiwan (in US$/MMBtu terms) is closely correlated to 15% of the crude price (i.e. LNG Price in US$/MMBtu = 15% x crude oil in US$/bbl). 15% is also the level of recently negotiated long term supply deals from new projects currently under construction in the Pacific region. This level is below energy parity pricing with crude oil at 17.6% (i.e. crude oil has an energy content of 0.176 MMBtu for every barrel), although some deals have been known to be priced much closer to crude oil parity.

Over the last few years, the Platts JKM (Japan Korea Marker) price has emerged as a traded price indicator in Asia, but is still quite illiquid and really only used to price short term or spot deals, with suppliers preferring more certainty in crude oil indexation to underpin project revenues (i.e. Brent). A potential shift in Asian LNG prices could come from major US LNG exports to Asia. Several long term supply deals have been completed over the last few years between Asian LNG buyers and LNG export projects currently under construction in the US. These deals have been based on Henry Hub prices, not crude oil indexation, and have generally been below crude oil indexed price levels (although this is being challenged by the recent collapse in crude oil prices that will feed through to Asian LNG contracts). US LNG export deals are generally priced at around 115%×Henry Hub (to account for 15% gas use in the liquefaction process) plus liquefaction fees of around US$ 3/MMBtu.

Publicly reported market and landed LNG prices for different regions around the world and Brent crude oil prices (six monthly rolling average – reflecting indexation to lagged oil prices in LNG contracts) are shown below.

*Figure 7.28: Regional monthly average gas and LNG prices*




*Source: QED Analysis*

For the purposes of this Study we have used the 15% level and a crude oil price of US$ 90/bbl – i.e. LNG price of US$ 13.5/MMBtu – as a Base Case market price that a Kenyan LNG project may expect to achieve. Using an estimated cost of shipping of around US$ 1.5/MMBtu (based on: US$ 200m capital cost and 10% of capex as annual operating costs per vessel, requirement for 12 x 170,000m$^3$ vessels to transport 10 mtpa from the Kenyan Coast to East Asia), this gives a Free-on-Board (FOB) netback price of US$ 12/MMBtu at the Kenyan Coast. Our Low Case market price assumption will be based on competition with US LNG export projects. We assume an FOB price of US$ 10/MMBtu, based on a Henry Hub price of US$ 4.5/MMBtu (×115%) + US$ 3/MMBtu for liquefaction and US$ 1.7/MMBtu for shipping from the US to the Kenya Coast. We will use these FOB Market price assumptions when considering netbacks to the wellhead and feed gas pricing requirements in section 7.2.

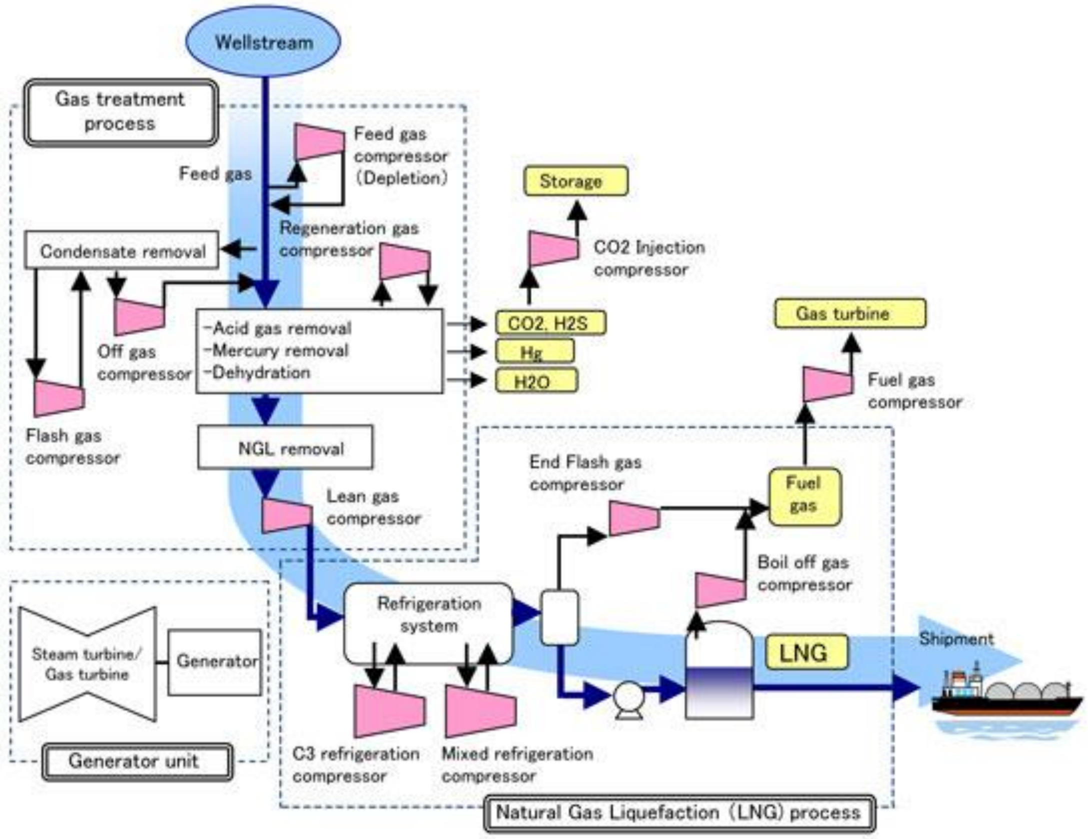
## *7.3.5.2. Production and transport*

### *7.3.5.2.1. LNG liquefaction plants*

When gas is delivered by pipeline to the LNG plant, the first step is to treat the gas to remove components which would interfere with processing, damage the plant (including $CO_2$, water and mercury) or are extracted for their value (mainly propane and butane and any remaining condensates). The degree of removal of these higher hydrocarbon components will establish the Gross Heating Value (GHV) and Wobbe Index (WI). The requirements for GHV and WI differ by importing country. The treated gas is then liquefied to approximately -160 degrees Celsius in a process using very large mechanical refrigeration cycles and propane, ethylene and methane as refrigerants under four key steps: compression, condensation, expansion and evaporation. The LNG product is then pumped into insulated storage tanks before being loaded on LNG carriers to be transported to LNG import terminals around the world.

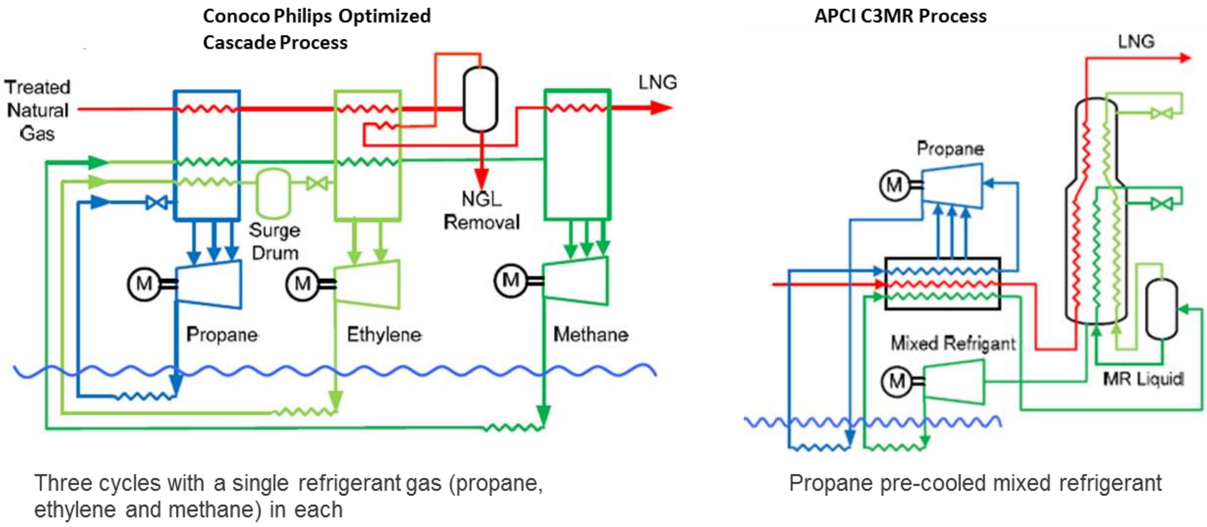
There are a number of liquefaction process technologies that have been developed by major IOCs over the years, including Conoco Philips, Shell, Exxon Mobil and Statoil. But most popular is the APCI's C3MR or AP-X Process designed by Air Products & Chemicals, followed by Conoco Philips' Optimised Cascade Process and Shell's C3MR and DMR processes.

*Figure 7.29: Overall LNG production process*




*Source: Mitsubishi Heavy Industries*

*Figure 7.30: Conoco Philip's optimised cascade and APCI's C3MR liquefaction process*




*Source: ABB Oil and Gas*

The most important requirement for the optimum design of an LNG liquefaction technology is to optimise the balance between power input and heat exchange area. The larger the heat exchange area the lower the temperature difference required which reduces the power required. Reduced power requirement leads to less consumption of gas to generate the power increasing plant efficiency and LNG output and lowering operating costs.

However, the refrigeration process only amounts to about 75% of the total energy required for the process. Energy is also required for fractionation and electric power for all machinery, lighting and heating. The total fuel requirement for the entire process typically ranges between 8% and 13% depending on liquefaction technology used, ambient conditions and gas composition.

For the purposes of this Study we will use an assumption of total gas consumption of 10%, i.e. 1 unit of gas input produces 0.9 units of LNG output.

A picture of Conoco Phillips' 3.5 mtpa Darwin LNG plant in Northern Australia, which came online in 2006, is shown below.

*Figure 7.31: Darwin LNG plant in Northern Australia*

*Source: Asia Pacific LNG*

The construction period for LNG projects is typically around 4-5 years, but is very dependent on the where the project is being developed in terms of its remoteness and availability of infrastructure, skilled labour and other resources, as well as other country specific and political factors.

### *7.3.5.2.2. LNG vessels*

LNG ships are mainly linked to specific projects and trade routes servicing long term (15-20 years) supply contracts between LNG buyers and seller. However, some players have developed their own shipping fleets to optimise trading of short term and spot cargoes. Volumes traded on a short term (1-4 years) or spot basis currently make up around 20-30% of total volumes traded. This means the pattern of new ships entering the fleet corresponds roughly to the pattern of FIDs in LNG projects. There are currently around 360 LNG ships in operation, most (80%) of which are between 122,000 to 177,000m$^3$ in capacity. The only LNG ships larger than 177,000 m$^3$ are the Q-Flex (215,000 m$^3$) and Q-Max (265,000 m$^3$) vessels associated with the Qatari projects. Given their size, these vessels are limited to certain ports globally.

There are two main types of LNG vessels – Membrane and Moss. In the membrane system, a thin nickel alloy or stainless steel membrane acts as the barrier between the LNG and the insulation (plywood boxes, load bearing balsa or mineral woods) against the inner surface of the ship hull. In Moss LNG vessels the ship has large spherical tanks made of aluminium or 9% nickel steel, covered on the outside by insulation. Pictures of each type of vessel are shown below.

*Figure 7.32: LNG vessel types*


*Source: Liquefied Gas Carrier Safety & Operational matters*

Nearly all Membrane or Moss vessels in operation before 2003 were powered by steam turbines. The major benefit of steam turbine engines is that any LNG cargo boil-off (evaporation) can be used as fuel in addition to fuel oil to power the engines.

However, in recent years diesel engines have been introduced into LNG ship design since they have the benefits of higher efficiency, reduced fuel consumption (higher thermal efficiency of diesel), reduce engine room size, lower lifetime and maintenance costs (given that not many other types of vessel still use steam engines). Hence the majority of new LNG vessels now being ordered are based on diesel electric propulsion. Some of these vessels are dual fuelled and are able to burn boil off gas as well as marine diesel oil. Vessels that operate solely on diesel employ a technology to reliquefy the boil off gas back into LNG; at present only the Qatari vessels use this technology.

Typical boil off rates are 0.125% of the cargo per day whilst laden and 0.15% per day whilst ballast. With boil off gas used as fuel, approximate fuel consumption is 3 tonnes of diesel per day whilst laden and 130 tonnes per day whilst ballast.

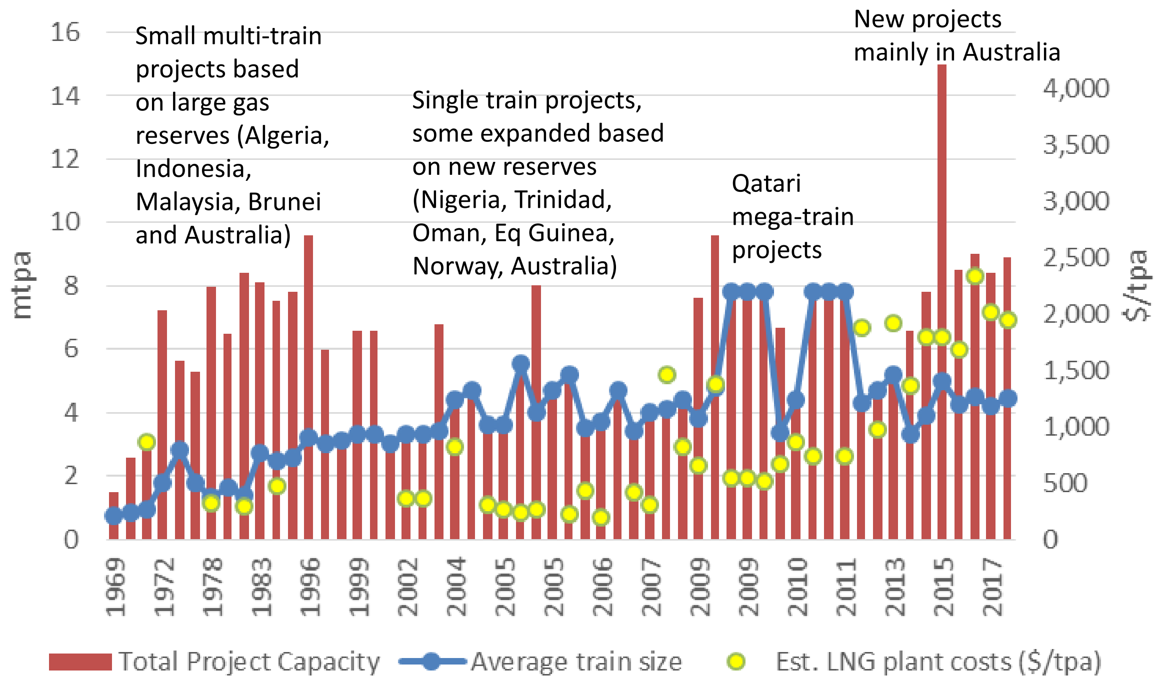
The construction period for a ‘standard’ size ship is about 2 years but this can depend on how full the order book is or how busy the shipyards are (Note: there are only a handful of shipyards set up to construct LNGCs).

## 7.3.5.3. Project scale

Project scale varies from project to project and mainly depends on the amount of gas reserves available to be monetised over the expected lifetime of the LNG plant, typically 30 years (though some of the earlier projects have now been operation for around 40 years).

LNG train size tends to differ between the various liquefaction technology providers, with certain providers having pre-established designs and sizes for their plants. The use of established designs and capacities can greatly enhance efficiency and reduce costs. As shown in the chart below, until the 1980s, LNG train size was relatively small and less standardised. Through the late 1990s and early 2000s, train size was typically around 3.3 mtpa. From around 2005, larger trains started to be developed, with train capacity reaching 5.2-5.5 mtpa for single train projects in Egypt, Trinidad (expansion) and in Angola. Qatar has been the only country to develop mega trains with capacity of 7.8 mtpa (based on a hybrid process developed by APCI and Exxon-Mobil). More recently, technology providers have expanded their standard designs and provide more bespoke sizing to better suit the needs of the project. Newer projects being developed in Australia have train sizes ranging between 4 and 5 mtpa.

*Figure 7.33: LNG project size and LNG plant costs*




*Source: QED Analysis*

What is more important to understand is the number of trains a given project has. Earlier projects were based on 3-8 trains in order to monetise gas from large gas fields. Between 2000 and 2010, many single train projects came online in order to monetise smaller gas fields – some were expansions of existing projects but developed and marketed LNG separately and were considered as separate projects. However, since 2010 there have been very few new single train LNG projects which have been brought online. The ones that have come online (Pluto LNG and Angola LNG) took FID in 2007 and incurred substantial project-specific delays before coming online.

The developers of LNG export projects have to now consider the economies of scale provided by a minimum of two trains in order to justify building the project due to record high costs for the LNG plant (which make up the majority of the overall total project costs) since 2011, as shown in the chart above. Costs are compared on the basis of their unit capital costs (total plant capex divided by the capacity, expressed as US$/tpa) and include costs for the liquefaction unit as well as LNG storage tanks and supporting infrastructure around the plant. These have been estimated by QED based on publicly reported costs by the project sponsors. Where only total costs are reported we have assumed a split between capital cost for the plant and for the rest of the project (mainly upstream and pipelines delivering gas to the plant).

As can be seen, costs of liquefaction plants have increased from around US$ 300-400/tpa before 2009 to between US$ 500 and US$ 1,000/tpa since the turn of the last decade. More recently, costs have more than doubled again to around US$ 2,000/tpa. Many factors have led to these increases in capital costs for new LNG plants, including:

- World-wide inflation and increase in commodity costs, especially in steel prices and crude oil prices
- Higher labour costs for developing recent projects in developed countries (e.g. Australia)
- Shortage of EPC contractor resource (only a handful of such contractors specialise in LNG projects) and high demand for developing LNG export projects
- Projects being developed in more remote and more challenging areas, with some incurring costly environmental restrictions

With many countries planning new LNG export projects, competition for resources is expected to remain strong over the next decade, which means costs for new greenfield plants are unlikely to return to pre-2010 levels or to sub-US$ 1,000/tpa. Therefore, for an LNG export project in Kenya, as with other countries planning greenfield LNG export projects, we assume a minimum of a two train 8-10 mtpa project will be required in order for the project to be economically feasible.

In terms of gas supply requirements, an 8-10 mtpa LNG plant would require 1,250-1,600 MMscf per day or 12.5-15.5 Bcm per year (including 10% gas auto-consumption) or approximately 13-17 Tcf of gas reserves, assuming a 30-year project life time.

### *7.3.5.4. Project costs*

Following on from above, in this subsection we provide estimates for a new greenfield LNG export project in Kenya. All costs projections are in Real US Dollars (2015 terms).

Despite there being very strong competition for resource over the last few years, this competition is predominantly from one region – Australia – where a large number of projects that are currently under construction are being developed in parallel. Costs for developing an LNG project in Australia can be assumed to be abnormally high, given high labour costs and the strengthening of the Australian dollar compared to the US dollar increasing the costs of imports. Australia has also experienced a large increase in the general prices of goods and services and hence labour compared to other regions around the world. We therefore expect costs for developing an LNG plant in other regions in the future to be somewhat lower than recently seen in Australia.

Our Base Case cost assumption for a two train liquefaction project in Kenya is US$ 1,400/tpa. This assumes the plant is developed near potential gas resources in Lamu and that there are no significant locational challenges/remoteness issues (i.e. imports of goods and delivery to the project site will be relatively easy through the development of a new port at Lamu). Our assumption of US$ 1,400/tpa is based on an average of US$ 1,750/tpa for the first train and 60% of this cost for the second train, which would benefit from some saving due to the use of common infrastructure. Assuming each train is 5 mtpa, this gives a plant capital cost of US$ 14b.

In the High Cost Case we assume specific LNG plant capital costs are US$ 2,000/tpa on average for both trains, giving capital costs of US$ 20b. In the Low Cost Case we assume the same assumption as the Base Case but with the development of a three train project – with the 3rd train also assumed to cost 60% of the first train – giving an average of US$ 1,280/tpa or US$ 19.25b, and a total capacity of 15 mtpa (providing more economies of scale).

Though not likely to be economically feasible, for comparison we will also make the assumption of developing a 1 train LNG export project of 5 mtpa at a specific capital cost of US$ 1,750/tpa giving capital cost of US$ 8.75b.

In terms of operating costs (cash costs at site level), the main elements are:

- Fuel gas consumption: estimated to be 10%, valued at the netted back LNG price
- Maintenance cost: estimated as 1% of the capital cost each year
- Labour costs: approximately 150 staff with minimum expatriates
- Local and national taxes

In general, total annual operating costs can be estimated to be approximately 3-5% of the total capital cost (excluding cost for fuel gas). We assume 3.5% for the purposes of the analysis in this Report.

### *7.3.5.5. Players and options for Government or NOC participation*

The main sponsors of LNG projects are usually National Oil Companies (“NOCs”) and International Oil Companies (“IOCs”) with some (minority) participation from LNG buyers. IOCs have a lot of the technical know-how in developing LNG projects and in managing EPC contractors and operations once the project is developed, and Governments of host countries usually require the NOC to be brought into the project as a way of securing additional revenues (in addition to taxation) for the country.

The main decision for the Government of a host country is to set the balance between direct investment by the NOC and the taxation element. This is typically done through negotiation with the other players in the project. However, the ability of the Government to take an equity stake will obviously depend on its ability and willingness to provide finance. Minority stakes tend to be held by less affluent Governments, but Government stakeholding has been known to change through the course of the project.

Key examples of where the NOC is the majority/largest shareholder include:

- Petronas in Malaysia (who own 60% equity in Malaysia LNG (23 mtpa) with Shell and Mitsui each holding 15%)

- Pertamina in Indonesia (who own 55% of Arun (6.5 mtpa) and Bontang (22.6 mtpa) LNG with ExxonMobil and Total as other major shareholders)
- Qatar Petroleum (who own 70% of Qatargas (41 mtpa) and RasGas (36 mtpa) with ExxonMobil, Shell and Conoco Phillips as other major shareholders)
- NNPC in Nigeria (who owns 49% of NLNG (21 mtpa) with Shell, Total and ENI as the other shareholders)
- Gazprom in Russia (who own 50% of Sakhalin LNG, with Shell, Mitsubishi and Mitsui as the other shareholders)

Sonatrach in Algeria, (who own 100% equity in its LNG projects (28.5 mtpa)) is an exception with a different business model, whereby Sonatrach buy gas from upstream producers including IOCs and sell LNG back to some of these players once liquefied.

Cases in which the NOC has a smaller shareholding include: Sonangol in Angola (23%); NGC in Trinidad (10%); EGAS and Egyptian Petroleum Co. in SEGAS (10% each) and Egypt LNG (12% each); and Sonagas in Equatorial Guinea (25%). Some LNG projects have no NOC participation, e.g. Peru LNG and Papua New Guinea LNG.

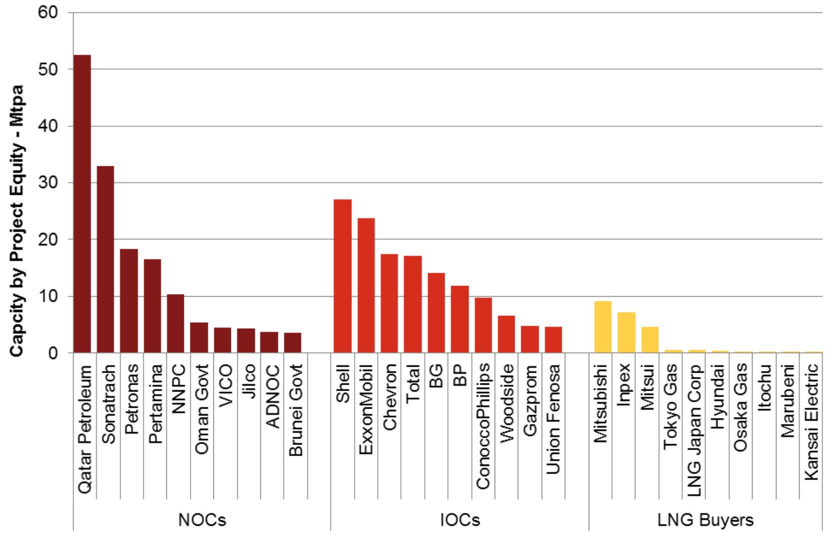
In developed countries such as Canada, US, and Australia, with liberalised gas markets, LNG project sponsors are mainly IOCs and large LNG buyers with, in some cases, participation from independent oil and gas companies that operate locally.

LNG buyers are increasingly willing to invest in LNG projects, historically for assurance on how the project was developing and for security of LNG supply through the project lifetime but more recently to gain access to their own 'equity' LNG volumes which they can then choose to market themselves. Some LNG buyers bring access to technology, operatorship and finance for the project. Most notably this list includes Japanese buyers and upstream players in the early Indonesian projects, and also recently in the Australian projects currently under construction. Market access and security of offtake through long term (15-20 years) contracts are still very important aspects for project lenders – especially given the very high upfront costs of developing such projects.

The amount of equity LNG buyers have in projects has historically been small (<5%), but nevertheless they offtake most, if not all, of the LNG. More recently, LNG buyers have been acquiring large positions in upstream resources. This may be in order to realise profits from gas production, to establish and lift their own 'equity' LNG from a project, or to get ahead of the competition in terms of having priority for participating in and securing the LNG from LNG projects. Examples of this include CNPC, KOGAS, Mitsui and PTT's involvement in upstream exploration and production in Mozambique and CNOOC and Petronas' acquisition of local upstream players in Canada.

The top ten players by total equity stake in different LNG projects is shown in the chart below (includes projects that are operational and under construction).

*Figure 7.34: Top ten equity holders by player type in LNG projects globally*




*Source: QED Analysis*

# 7.4. Gas Development Scenarios Modelling

As part of developing this Study, a financial / economic model was built with the objective of evaluating the viability or feasibility of the different gas monetisation options as identified earlier.

The gas financial / economic model estimates netback values from market prices for the key monetisation options under consideration. Netbacks are determined at the plant gate (i.e. the inlet for gas supply to the plant), deducting unit costs of production from assumed market prices, and providing an indication of the maximum feedgas price (in US$/MMBtu) that the project can afford to make an assumed rate of return. Generally: Netback price = Market price – Cost of Production

The model analyses costs of production for the different gas monetisation options based on assumed financing packages, opex and capex assumptions, and also examines netback prices based on different market prices. Results are presented in Real$ 2015 values, assuming the investment decision is made at the start of 2015 and accounts for the construction time and hence capex spread for different monetisation options.

A sensitivity analysis on capex and market prices is undertaken to understand the impact on production costs, project economics, and affordability of gas supply at the plant gate. Here we provide 'book-end' cases to understand determine Adverse Case and Favourable Case estimate of netback prices. 1. Adverse Case assumes high capex and low market price assumptions. 2. Favourable Case assumes low capex and high market price assumptions.

Assumptions for project scale, market pricing, capex and opex costs are discussed in detail for each monetisation option in Section 7.3. Additional details on the model methodology and funding assumptions have been presented in Appendix K.

The model analyses five key monetisation options:

- An 800MW Gas-fired power plant (CCGT)
- A minimum 2 train Liquefied Natural Gas (LNG) plant
- A 1mtpa Ammonia or Methanol plant (market prices, costs, scale and gas requirements assumed to be similar for each as discussed in Section 7.3)
- Gas transmission pipeline (for three major routes: 1) Lamu-Mombasa (300km, offshore), 2) Mombasa-Nairobi (450km), 3) Lamu-Isiolo/Meru-Nairobi (750km))

Financing assumptions:

- DFI Loans – Indicative terms:
  - Tenure = 15 years,
  - All in interest rate = 5.40%,
  - Grace on principal repayment of debt = Between 2 to 5 years
- Commercial Banks – Indicative terms:
  - Tenure = 7 years,
  - All in interest rate = 6.90%,
  - Grace on principal repayment of debt = Between 1 to 2 years
- Commercial Banks with refinancing option – Indicative terms:
  - Tenure = 5 years,
  - All in interest rate = 7.82%
- Concessional Loans - Indicative terms:
  - Tenure = 25 years,
  - All in interest rate 1.40%,
  - Grace period on principal repayment of debt = 10 years

Additional financing costs have also been considered under each financing source, including: front-end fee, commitment fee and arrangement fees that are likely to emerge.

Note: The results presented below for each monetization option achieves an Internal Rate of Return of 15%.

### *7.4.1. Modelling Results*

#### *7.4.1.1. Gas fired power generation*

*Table 7.11: Model Assumptions – Gas Fired Power Plant*

| Assumption | Value |
|---|---|
| **Plant Size** | 800MW |
| **Thermal Efficiency** | 55% |
| **Load Factor** | 60% |
| **Capital Cost** | Base Case – US$ 875m<br>High Case – US$ 1,040m<br>Low Case – US$ 600m |
| **O&M Cost** | 4% of Capital Cost |
| **Market Price** | Base Case – 100 US$/MWh<br>High Case – 130 US$/MWh<br>Low Case – 70 US$/MWh |
| **Funding Mix** | DFI – 75%<br>Commercial – 25% |

*Source: PwC Consortium Analysis*

The funding mix for the development of a gas fired power plant is benchmarked against likely funding Independent Power Producers attract in the Kenyan market. This does of course vary across different power projects, however we consider that investors would look to attract favourable funding terms from DFIs while maintaining commercial lending that would allow for the flexibility to refinance. We note there have been IPPs that are capable of attracting concessional type funding, however these are typically extended to promote the use of renewable energy and may not necessarily be seen in the financing of gas fired power generation.

*Table 7.12: Model Results – Gas Fired Power Plant*

| Modelling Case | Indicative Tariff (US$/MWh) | Max Feedgas Cost (US$/MMBtu) |
|---|---|---|
| **Base Case Capital Cost**<br>**Base Case Market Price** | 37.91 | 10.01 |
| **<u>Adverse Case:</u>**<br>**High Case Capital Cost**<br>**Low Case Market Price** | 43.43 | 4.28 |
| **<u>Favourable Case:</u>**<br>**Low Case Capital Cost**<br>**High Case Market Price** | 28.72 | 16.33 |

*Source: PwC Consortium Analysis*

Given the lower capital costs in the favourable case, a lower cost of production of US$ 28.72 / MWh is estimated, which means the cost of gas supply at the plant gate can be as high as US$ 16.33 / MMBtu. This compares to the adverse case where the high capital cost gives an estimated cost of production of US$ 43.43 / MWh and hence the maximum affordable gas supply cost at the plant gate of US$ 4.28 / MMBtu.

## *7.4.1.2. LNG Export Plant*

*Table 7.13: Model Assumptions – LNG Export Plant*

| Assumption | Value |
|---|---|
| **Number of Trains** | Minimum 2 train LNG Plant |
| **LNG Train Size** | 5 mtpa |
| **Capital Cost** | Base Case – US$ 14,000m<br>High Case – US$ 16,000m<br>Low Case (3 train) – US$ 19,250m |
| **O&M Cost** | 3.5% of Capital Cost |
| **Market Price** | Base Case –12 US$ / MMBtu<br>High Case – 14 US$ / MMBtu<br>Low Case – 10 US$ / MMBtu |
| **Funding Mix** | DFI – 60%<br>Commercial – 10%<br>Concessional – 30% |

*Source: PwC Consortium Analysis*

Given the high cost nature of a Liquefied Natural Gas plant, we assumed this project would attract concessional type financing with considerably lower pricing in comparison to DFI and commercial lending that would promote the project returns and hence improve the financial viability of such a capital intensive project.

*Table 7.14: Model Results – LNG Export Plant*

| Modelling Case | Indicative Tariff (US$/MMBtu) | Max feedgas cost (US$/MMBtu) |
|---|---|---|
| **Base Case Capital Cost**<br>**Base Case Market Price** | 5.84 | 6.16 |
| **<u>Adverse Case:</u>**<br>**High Case Capital Cost**<br>**Low Case Market Price** | 6.17 | 3.83 |
| **<u>Favourable Case:</u>**<br>**Low Case Capital Cost**<br>**High Case Market Price** | 5.43 | 8.57 |

*Source: PwC Consortium Analysis*

The favourable case with a lower capital cost will yield an estimated lower cost of production of US$ 5.43 / MMBtu, which means costs of gas supply at the plant gate can be as high as US$ 8.57 / MMBtu. This compares to the adverse case where the higher capital cost gives an estimated cost of production of US$ 6.17 / MMBtu and hence a maximum affordable gas supply at the plant gate of US$ 3.83 / MMBtu.

### 7.4.1.3. Ammonia or Methanol Plant

*Table 7.15: Model Assumptions – Ammonia or Methanol Plant*

| Assumption | Value |
|---|---|
| **Production** | 3,000 tonnes per day |
| **Capital Cost** | Base Case – US$ 1,200m<br>High Case – US$ 1,800m<br>Low Case – US$ 750m |
| **O&M Cost** | 5% of Capital Cost |
| **Market Price** | Base Case – 12.50 US$ / MMBtu ($350 / t)<br>High Case –17.86 US$ / MMBtu ($500 / t)<br>Low Case –8.93 US$ / MMBtu ($250 / t) |
| **Funding Mix** | DFI – 75%<br>Commercial – 25% |

*Source: PwC Consortium Analysis*

The financing assumptions for the development of an Ammonia / Methanol plant are similar to those for gas fired power generation. For the purposes of comparing netbacks, we have not assumed a case where such projects would attract concessional type funding, however this cannot be ruled out as there are a number of DFIs that could assist in introducing concessional funding to projects depending on the forecast project economics.

*Table 7.16: Model Results – Ammonia or Methanol Plant*

| Modelling Case | Indicative Tariff (US$/MMBtu) | Max feedgas cost (US$/MMBtu) |
|---|---|---|
| **Base Case Capital Cost**<br>**Base Case Market Price** | 8.13 | 4.37 |
| **Adverse Case:**<br>**High Case Capital Cost**<br>**Low Case Market Price** | 10.99 | -2.06 |
| **Favourable Case:**<br>**Low Case Capital Cost**<br>**High Case Market Price** | 6.03 | 11.82 |

*Source: PwC Consortium Analysis*

Given the favourable case has a lower capital cost, a lower cost of production of US$ 6.03 / MMBtu is estimated, which means the cost of gas supply at the plant gate can be as high as US$ 11.82 / MMBtu. In the adverse case, the ammonia / methanol plant would be unviable.

### 7.4.1.4. Gas Pipeline Costs

As with the estimated costs of production for the different monetisation options assumed above, we have indicative tariffs for cost of gas transportation for major gas pipeline routes as discussed in section 7.3. **Gas transportation costs would effectively form part of the cost of gas supply to such projects, and hence reduces the maximum affordable cost of gas assumed above by the cost of transportation**. The financing structure for gas pipelines assumed a mix of DFI, Commercial and Concessional where the lower pricing terms of Concessional terms will improve the project financial viability through promoting the project returns while reducing the tariff to the end user. For example, the natural gas pipeline from Mnazi Bay to Dar es Salaam in Tanzania attracted concessional funding from Export-Import Bank of China[23].

[23] http://www.theeastafrican.co.ke/news/-1-2b-project-to-end-Tanzania-power-rationing/-/2558/1616770/-/lfxl78/-/index.html

*Table 7.17: Model Assumptions – Gas Pipeline*

| Assumption | Value |
|---|---|
| **Pipeline Capacity** | 5 Bcm/year |
| **Capital Cost** | Lamu – Mombasa: US$ 780m<br>Lamu – Isiolo – Nairobi: US$ 1,275m<br>Mombasa – Nairobi: US$ 765m |
| **O&M Cost** | 4% of Capital Cost |
| **Funding Mix** | DFI – 65%<br>Commercial – 20%<br>Concessional – 15% |

*Source: PwC Consortium Analysis*

*Table 7.18: Model Results – Gas Pipeline*

| Modelling Case | Indicative Tariff (US$/MMBtu) |
|---|---|
| **Lamu – Mombasa** | 0.71 |
| **Lamu – Isiolo – Nairobi** | 1.05 |
| **Mombasa – Nairobi** | 0.70 |

*Source: PwC Consortium Analysis*

Cost of transportation vary mainly by distance and volume transported (economies of scale) – assumed to be 5Bcm/yr for each line. Costs should be much lower than for the cost of gas itself in order for the overall cost of gas supply to be affordable. The costs shown above expected to be in line with this.

### 7.4.2. Conclusions

In determining options for gas monetisation demonstrating viable project economics will be key to attracting financing and hence the development of gas projects. Construction costs for projects is generally well understood before taking a final investment decision through pre-FEED and FEED activities. However, there is considerable uncertainty with respect to product market pricing particularly for exports where market prices can be determined by global supply and demand.

As shown above, gas products projects (ammonia/methanol production) typically require cheap indigenous sources of gas with a delivered cost of no more than $4.37/MMBtu to the plant in thee Base Case. This is not much higher than the estimated costs of production of around $4 - 5 / MMBtu for onshore or close to shore gas plays. If plant costs were to increase or market prices were to decrease the project would no longer be economic.

LNG projects, despite having much higher plant costs are considerably larger in scale (10 mtpa versus 1mtpa for ammonia/methanol). Netbacks to the plant gate in the Base Case are around $6 /MMBtu, which is not much higher than estimated costs of production, but may be sufficient given the much larger project scale.

Netbacks for gas use in power generation are generally much higher particularly if alternative forms of power generation are more expensive in terms of fuel costs (e.g. oil) or capital costs (e.g. hydro, nuclear, coal). In the Base Case we estimate that these projects can afford gas supply at around $10 / MMBtu. However, being based inland and closer to demand centres, costs of gas transportation would be larger and would need to be taken into account as part of the gas supply cost. This assumes a market price of $100/MWh or ¢$10/kWh, which although lower than current power prices in Kenya but still above the ¢$7-8/kWh ($70-80/MWh) the GoK is aiming to get to. If we assume an Adverse Case with high capital costs and low market prices of $70/MWh, maximum gas supply costs afforded drops to $4.28 / MMBtu, which may not be economically feasible. If we assume Base Case capital costs and market prices of $80/MWh, maximum gas supply costs is just below $7 / MMBtu, which may be sufficient for power plant developers and gas producers.

The information provided in this section can be used as an indication to understand the economics and maximum gas supply costs afforded for gas projects under different cost and price assumptions. This can be used by the GoK in negotiating gas price terms with upstream producers. However it stressed that these are high level indications and more detailed modeling would be required to take into account the specific aspects and understand the economics of actual gas projects being considered.

# 7.5. Gas Strategic Alternatives

## 7.5.1. Introduction

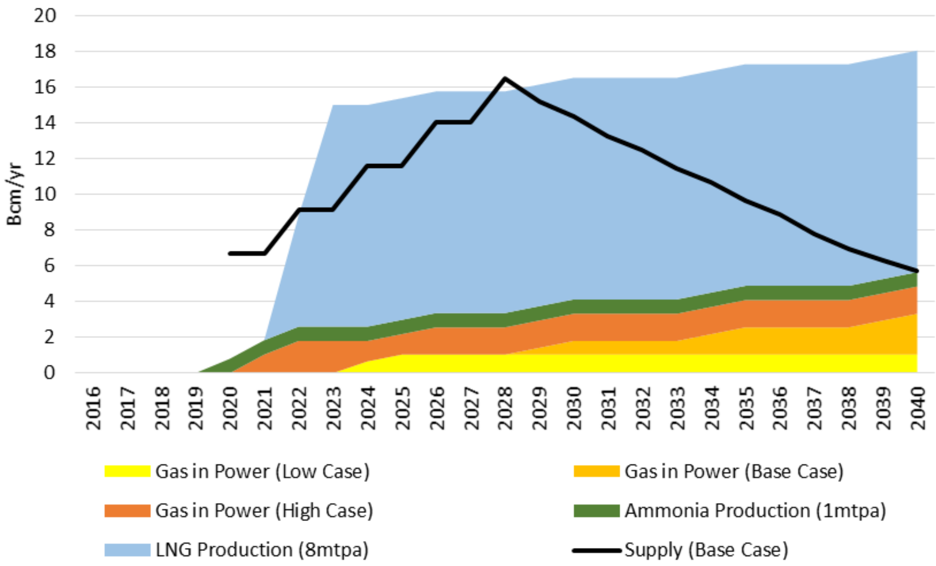
In this section we provide a comparison of potential gas supply and demand in Kenya, as previously discussed in section 7.2.3. We provide commentary on the differences between potential supply and demand and the implications this may have for the development of the gas industry. It is important to recall that Gas Supply Potential is based on current information on exploration activity, which is still at very early stages, and that Gas Demand Potential for power generation is highly dependent upon the growth of electricity demand.

We then discuss the start-up of the natural gas industry in Kenya, and in particular the role an LNG import project could still play and the potential replacement of LNG imports with indigenous gas supply. We describe the key strategic considerations for gas project siting and requirements for gas infrastructure under different growth scenarios. For gas supply to power generation (CCGT), we comment on the decision making between the development of gas pipelines versus power transmission lines, taking into account current and future plans of GoK. In conclusion, we outline the critical success factors and commercialization challenges for the successful development of the Kenyan natural gas sector.

## 7.5.2. Supply / demand comparison

Gas supply and demand projections under our Base Case and alternative scenarios have been discussed in detail earlier in this Report and they are summarised below.

*Figure 7.35: Base case potential gas supply and demand in Kenya*




*Source: PwC Consortium Analysis*

As discussed through the Study, based on the information currently available from exploration activity undertaken to date, in the Base Case for supply potential there is an insufficient amount of gas resource to consider the development of an LNG export project in Kenya. Given high plant costs, LNG production requires large economies of scale and is now really only developed as a minimum two train project. A collapse in LNG market prices, driven by a drop in crude oil prices, only heightens the requirement for economies of scale. An assumed 8 mtpa LNG plant would require gas supply of around 12.5 Bcm/yr sustained for the life of the project, typically 30 years.

Assuming LNG exports do not occur in the Base Case, and pipeline exports are also limited, gas producers would have to consider options for supplying gas into the local market, with the key option being power generation. As shown above, in the Base Case for supply potential, there is a potential excess of gas supply even assuming High Case demand for gas-fired-power generation. This is mainly due to the limited demand for gas in the power sector given competition from other sources of power generation (mainly geothermal, which is targeted to reach some 5,000MW by 2030 from current levels of around 600MW).

As discussed in section 7.2.3.1.1, in the Base Case, gas demand for power generation is assumed to be 1 Bcm/yr in 2025 supplying 1,085MW of gas-fired power generation capacity, increasing to 1.8 Bcm/yr in 2030 (supplying 1,885MW), 2.6 Bcm/yr in 2035 (supplying 2,685MW) and to 3.3 Bcm/yr in 2040 (supplying 3,485MW). In the High Case, gas demand for power generation is assumed to start earlier than in the Base Case, at 1.8 Bcm/yr in 2022 supplying 1,885MW of gas-fired power generation, increasing to 2.2 Bcm/yr in 2025 (supplying 2,285MW), 3.3 Bcm/yr in 2030 (supplying 3,485MW), 4.1 Bcm/yr in 2035 (supplying 4,285MW) and to 4.8 Bcm/yr in 2040 (supplying 5,085MW).

To the extent that other forms of power generation do not materialise (particularly geothermal – as we assume no coal fired-power generation gets developed in our Base and High Cases), additional gas-fired power generation can be developed relatively quickly, subject to gas supply being available. However, it is unlikely that all gas supply available in the Base Case gets supplied into power generation simply because of the constrained size of the overall power market. For example 12 Bcm/yr would be sufficient to supply 12,000MW, which equates to the total assumed demand for power in 2040.

In terms of other local gas monetisation options, key ones being ammonia and methanol production, due to a limited international market and relatively small local and regional markets (with neighbouring countries also planning projects), we assume only one world-scale ammonia project with capacity of 1 mtpa, requiring total gas supply of 0.8 Bcm/yr is developed to meet local demand in Kenya (expected to reach 1.4 mtpa by 2030).

Hence, in the Base Case for supply potential, we assume there is an excess of gas supply compared to local gas demand. However, the above supply and demand projections are theoretical and any actual gas production would obviously be optimised to match demand or more specifically supply/offtake commitments. Furthermore, any investment in upstream gas will be contingent on identifying economically attractive routes for monetisation beforehand.

It will be important for the Government of Kenya to promote the rapid development of the local gas market, thereby providing exploration companies with more assurance with regard to marketing any gas finds, i.e. resources will only be developed if upstream players have an economic offtake option. Increasing exploration may then lead to a High Supply Potential Case, through discovering a major gas find or aggregating several smaller finds. This, in turn, then provides a better case for developing major export projects, likely to be through LNG given the limited potential for exports via pipeline to neighbouring countries. These issues, the commercialization challenges of developing the local gas industry and the decision making requirements by the Government of Kenya will be discussed in more detail at the end of this section and in the Recommendations. Below we outline strategic considerations for the development of the local gas market based on gas-fired power generation and using indigenous gas supply. We assume the development of the gas industry starts between 2020 and 2025 to reflect timing for when indigenous gas supply may potentially come online and for when additional power generation capacity may be required. If a role for gas-fired power generation is required sooner than expected, we discuss below how an LNG import project may be suitable to kick start gas supply in the short term.

### 7.5.3. LNG imports kick starting the development of the gas industry

The Government of Kenya has previously considered the joint development of an LNG to power project based on a floating LNG import terminal (Floating Storage and Regasification Unit – FSRU) and at least 700MW of gas-fired power generation. The project was originally intended to be developed to provide power generation by 2017 as part of the GoK's 5000+MW plan to meet Kenya's rapidly growing power demand in the short-medium term and beyond. With indigenous gas resources only recently being discovered, the project did not consider replacement of LNG supply with indigenous gas supply if and when it becomes available, with GoK considering imports of LNG on a long term basis. The project has recently been cancelled, and we now consider the short term role LNG may play in kick-starting the development of the local gas industry and indigenous gas supply.

With the proposed terminal being based on an FSRU vessel, the FSRU can be redeployed if no longer required as has been done (or is planned) in other countries around the world. This allows FSRU providers to lease the vessel for a lower number of years (5 year term deals have been agreed) to countries looking to alleviate gas supply shortages in the shorter term.

In the case of Kenya, short term LNG imports through a FSRU terminal provides an opportunity to start gas supply to newly developed gas-fired power plants and to re-fire nearby oil-fired power plants (in Mombasa) before indigenous gas supply is brought online. With LNG to power projects able to be brought online in a minimum of 2 years (2 years being the minimum amount of time required to develop the power plant with the terminal only taking 1 year to be developed, subject to FSRU availability) there are benefits of these projects compared to other forms of reliable (i.e. non-renewable) power generation if there is perceived shortage of power generation capacity in the short-medium term.

With the considerable amount of geothermal power generation which has recently come online (c.300MW in 2014), Kenya is currently experiencing an oversupply of power generation capacity. With geothermal currently planned to increase to over 1,000MW by 2020 and 5,000MW by 2030, the development of an LNG to power project to meet power demand may not be required. However, if geothermal fails to materialise to this extent and Kenya finds itself short of reliable power generation, then a strong case for an LNG to power project can be made. Importantly, LNG imports would be cheaper than meeting the supply-demand gap by developing additional oil-fired power generation which has been the case in the last few years (with close to 200MW being brought online in 2014 adding to the 500MW of existing capacity) and competitive with imported coal, and offering clear environmental benefits over both of these options.

However, in the case of Kenya, with no local gas market, it is equally important to provide assurance to upstream players on the development of the local gas market. Upstream players who have discovered indigenous gas resource may not be sufficient enough to develop an LNG export project would require firm local monetisation options if they were to invest in the upstream sector. Developing gas-fired power plants supplied initially through LNG imports which can then be replaced by indigenous gas supply under long term contracts will provide more assurance on upstream investment and allow time to bring gas production online (not less than 3-5 years from confirmation of recoverable reserves).

Given the uncertainties over power related growth rates and when potential indigenous supply can come online, we do not make any assumptions on exactly when an LNG to power project can be developed, but discuss below options for developing LNG to power on a medium term basis and then substitution with indigenous supply as and when it potentially becomes available.

### 7.5.4. Ammonia/methanol and LNG export plant siting

In terms of ammonia/methanol, project siting would usually need to be close to point of consumption or export. This is because the cost of gas pipeline transportation is generally less than the cost of transporting the finished product to the point of export or consumption by truck, particularly if the gas pipeline use is also shared with other users. If volumes are small and long distance pipelines are required then this may not necessarily be true. In the case of Kenya, with large potential gas reserves located in the Coastal Lamu Basin, it would make sense to develop any export focused plant on the coast and close to gas reserves. In the case of ammonia, which is expected to be used to meet domestic demand in the agricultural Central and Western parts of the country, the benefits of developing an ammonia plant jointly with an export focused methanol plant would need to be weighed up against the cost of trucking product to the point of consumption inland. With potential gas resources also in Northern Kenya, in the Anza Graben Basin, options also exist for developing the ammonia plant near gas resources in Northern Kenya or acting as an anchor load (in conjunction with gas-fired power plants) closer to demand centres in Central/Western Kenya.

Regarding potential LNG exports, an LNG export plant has to be located on the coast and sometimes requires long distance gas pipelines in order to do so. In the case of Kenya, in the High Supply Potential Case sufficiently large gas resources for an LNG project are assumed to be located in the Coastal Lamu basin, just offshore Lamu. Hence an LNG plant is likely to be located on the coast near Lamu where water is deep enough to build a jetty for vessel berthing. If onshore locations prove problematic, then it may be possible to consider an offshore floating liquefaction facility, such as the projects being developed offshore Australia and Mozambique. A pipeline would be developed straight from the offshore fields/gathering point to the plant, where gas is then processed, liquefied and loaded onto the LNG vessel. An onshore project would most likely have its own jetty and marine facilities – there is little to be gained (e.g. the loading gantries and dolphins are of quite different heights from crude oil shipment needs) but considerable risk from the shared use of jetties.

### 7.5.5. Gas-fired power plant siting

With power demand spread across the country and with options for power versus gas transmission, there are more options regarding gas-fired power plant siting. Furthermore, there are already plans underway for the development of new power transmission lines and gas-fired power plants in Kenya, which we will consider.

In the Base Case for gas demand in power generation, we assume 800MW of new gas-fired capacity is brought online in the coastal region in addition to the conversion of 285MW of existing oil-fired power generation in and around Mombasa (195MW at Kipevu, and 90MW at Rabai) around the same period. Assuming gas is initially supplied through LNG imports, then the development of these initial plants can be earlier.

With gas resource and potential gas supply from the Coastal Lamu Basin and Offshore Mombasa, we assume the potential coastal gas-fired power plants can be developed anywhere along the coast, depending on when gas supply can potentially come online from each area. Developing a plant(s) between Mombasa and Kilifi may be optimal, taking into account demand growth in the Mombasa, previous gas-fired power generation plans, existing power transmission plans and requirements to supply gas to the existing 285MW of oil-fired plants in Mombasa. In which case, gas supply from Lamu can be transported through the development of an onshore or an offshore coastal gas pipeline to Mombasa.

The development of coastal gas-fired power projects would be consistent with existing plans for the development of 400kV power transmission lines from Lamu (where new coal and wind power generation is planned) to Kilifi (just north of Mombasa) to Mariakani (just outside Mombasa) and on to Nairobi (where the majority of Kenya's power demand growth is expected). 400kV lines can transport power supply from up to around 1,000MW of power generation capacity and may therefore have to be further developed in order to transport power from these various coastal power plants.

Gas resource and hence gas supply is also potentially available in the Anza Basin in Northern Kenya. The closest major power demand centre to this resource is in the Mt Kenya region (Isiolo, Meru, Nanyuki). Though this gas can be used in new gas-fired power generation in this region, depending on when it may become available, we also discuss how gas from Anza can be integrated with a wider gas supply network from Lamu to Nairobi.

Post-2025, in the Base Case for gas demand in power generation we assume a further 800MW is developed in each of the periods around 2030, 2035 and 2040. It is more likely the additional capacity in each of the periods are developed as individual projects located closer to demand centres where anticipated growth is highest. This assumption takes into account typical power plant turbine sizing of around 400MW (as discussed in section 7.2.3.3) and concentration of demand and hence power plant siting in major cities across Kenya, the key one being Nairobi.

In terms of siting, irrespective of gas resource location, it may be optimal for additional gas-fired power plants to be developed further inland and closer to key demand centres in Central Kenya, allowing gas supply to smaller gas users (e.g. industrial consumers) established along main gas pipeline routes or to other oil-fired power plants with potential to be converted like at Tsavo (74MW) or in Nairobi (Iberafrica-108MW), thereby also reducing the requirement for additional power transmission. Obviously some plants may still need to be developed along the coast to meet coastal power demand, but demand growth is expected to be lower than in Central Kenya.

From the Coast to Nairobi, options for gas supply to inland power plants exist under two main options:

1) From Lamu along the LAPSSET corridor to Isiolo and Meru (where is joins potential gas supply from the Anza Basin in Northern Kenya) and then down to Nairobi; and,
2) From Mombasa to Nairobi – potentially following the same route as the existing oil products pipeline with the option of gas supply also from Lamu via the coastal pipeline to Mombasa.

However, we also considered alternative options and the benefits of developing gas-fired power plants at or near Nairobi (instead of at the Coast) with gas pipelines from the coastal region to Nairobi either instead of or in addition to the proposed new power transmission lines.

Options for developing gas-fired power generation and gas and power supply infrastructure around Kenya are considered in more detail under the three scenarios below. These are described at a high level and aim to promote thought on the options available. In each case, we have allowed for the kick-starting of the Kenyan gas industry by imported LNG, which would be displaced by indigenous gas production. However, if LNG import is not pursued then these scenarios continue to be relevant based on indigenous supply only.

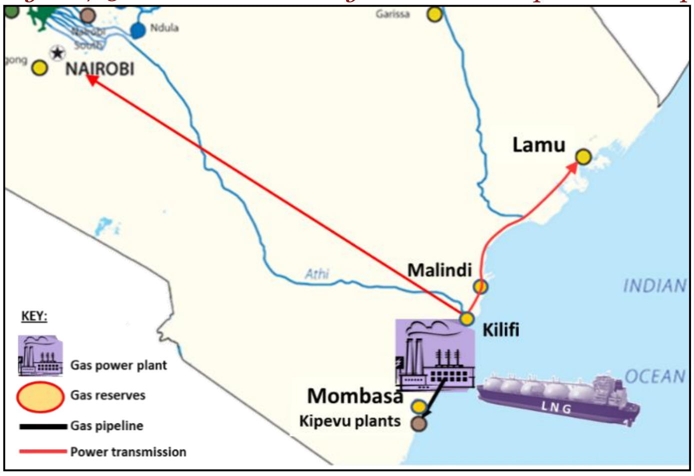
No scenario is preferred at this stage and more detailed planning and evaluation would be required, taking into account all important factors including *inter alia* plans for the power sector.

## 7.5.5.1. Scenario 1: Coastal CCGT plant development and power transmission

Scenario 1 assumes the development new gas-fired power generation in Mombasa or between Mombasa and Kilifi, and the conversion of oil-fired power generation (at Kipevu and Rabai, in and near Mombasa respectively) by 2025. We also assume the development of a 400kV power transmission line from Kilifi to just outside Nairobi (Kangundo) and from Kilifi to Lamu, where major port and other developments are expected before new Lamu power generation is brought online (Note: as shown below, we assume power supply can be reversed at a later date if required). A new pipeline would be required to supply gas to the existing 285MW oil-fired plants to be converted to gas at Kipevu and Rabai. If the gas power plants are developed outside Mombasa the gas pipeline to the converted oil power plants can be routed offshore via the Kilindini Port.

In the figure below, we assume the early development of gas-fired power generation, with gas initially supplied to the new and converted power plants through the import of LNG, requiring around 100 MMscf of gas supply per day, equivalent to 1 Bcm/yr, or 0.75 million tonnes of LNG per annum.

*Figure 7.36: Scenario 1: Early coastal CCGT plant development and power transmission*

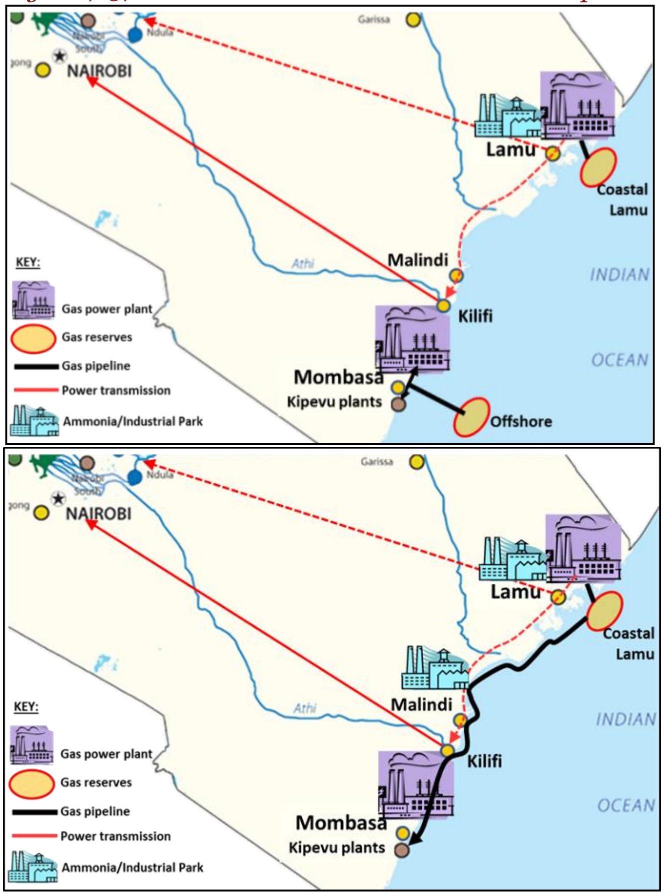



*Source: PwC Consortium*

We assume LNG supply can be replaced by potential indigenous production from Coastal Lamu or Offshore Mombasa. Exactly when this can happen will depend on when gas supply comes online. We have assumed that production can potentially become available by 2025, but this is contingent upon successful exploration drilling and agreement of acceptable terms for both the Government and producers before major production activity takes place, which can take time. It may even be preferred to complement/supplement indigenous supply with LNG for several years, although the likely difference in delivered gas price may prohibit this. Nevertheless, the LNG facility could continue to provide Kenya with energy security of supply in the long term through the ability to import spot cargoes.

We assume new power generation at Lamu, with options for power transmission from Lamu to Nairobi via Kilifi or direct to Nairobi, as is currently being considered.

Figure 7.37: Scenario 1: Base case coastal CCGT plant development and power transmission




*Source: PwC Consortium*

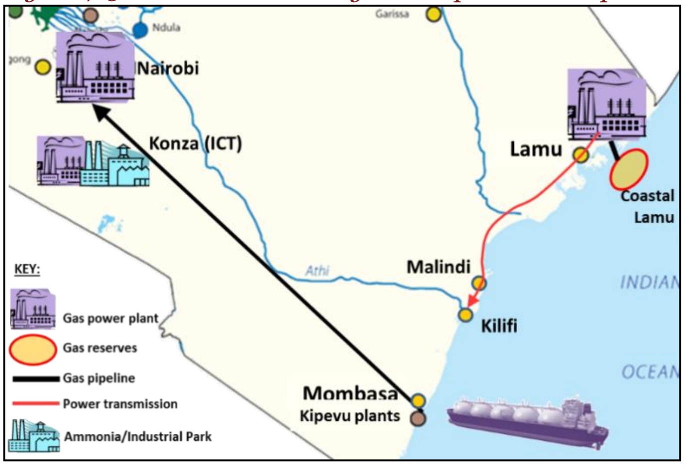
If gas supply Offshore Mombasa is not available, a c.300 kilometre offshore or onshore gas pipeline would need to be developed along the coast to the plants in Mombasa or between Mombasa and Kilifi and backfill the smaller pipeline to the Kipevu and Rabai plants. Developing the gas pipeline offshore may provide cost savings but in any case would be easier and quicker to develop without requirements for way leave or rights of way. The gas pipeline also provides options for offtake along the way, for example to supply gas to potential ammonia, methanol or other power projects between Lamu and Mombasa. Power transmission options from Lamu to Nairobi via Kilifi (and Mariakani) or direct is considered. The same principle holds if gas supply from Lamu is not available, though based on current information on gas resource potential, the Coastal Lamu Basin is assumed to hold more gas resource than Offshore Mombasa.

## 7.5.5.2. Scenario 2: Inland plant development and gas transmission

In Scenario 2 we outline the case for developing new gas-fired power generation inland, closer to the key demand centre of Nairobi. This would require constructing a c.450 kilometre gas pipeline, which would be able to provide gas offtake along the way for areas such as Konza, where an Information Communication and Technology park is planned requiring 440MW of power supply, and other areas where Industrial parks may be developed. In addition, there are other existing oil-fired power plants with potential to be converted to gas at Tsavo and in Nairobi (Iberafrica).

In the figure below, as with Scenario 1, we assume early development through gas being initially supplied through the import of LNG. We also assume that there may be some early gas supply from Coastal Lamu that can be used for power generation in Lamu with supply to other towns and demand centres along the coast.

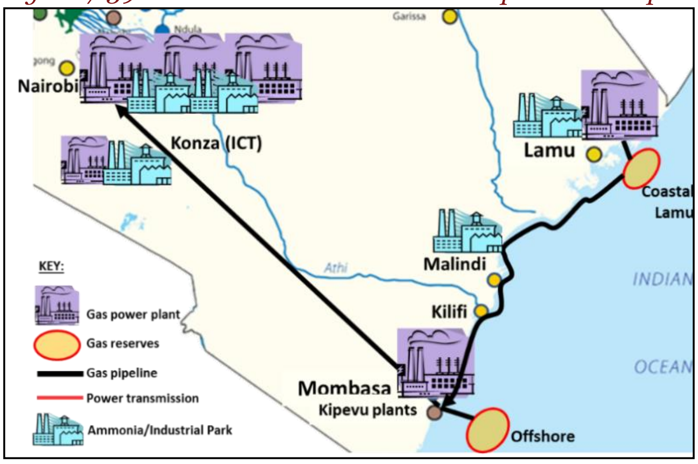
*Figure 7.38: Scenario 2: Early inland plant development and gas transmission*




*Source: PwC Consortium*

We assume LNG can be replaced by Offshore and/or Coastal Lamu potential gas supply. Gas supply would continue to Nairobi through the existing but expanded gas pipeline, where additional gas-fired power plants can be developed, closer to this key demand centre in the future. As discussed above, gas pipelines encourage supply to other projects and industries. This allows the development of gas use by existing and new industry near Nairobi or along the pipeline route, on the coast or inland.

*Figure 7.39: Scenario 2: Base case inland plant development and gas transmission*



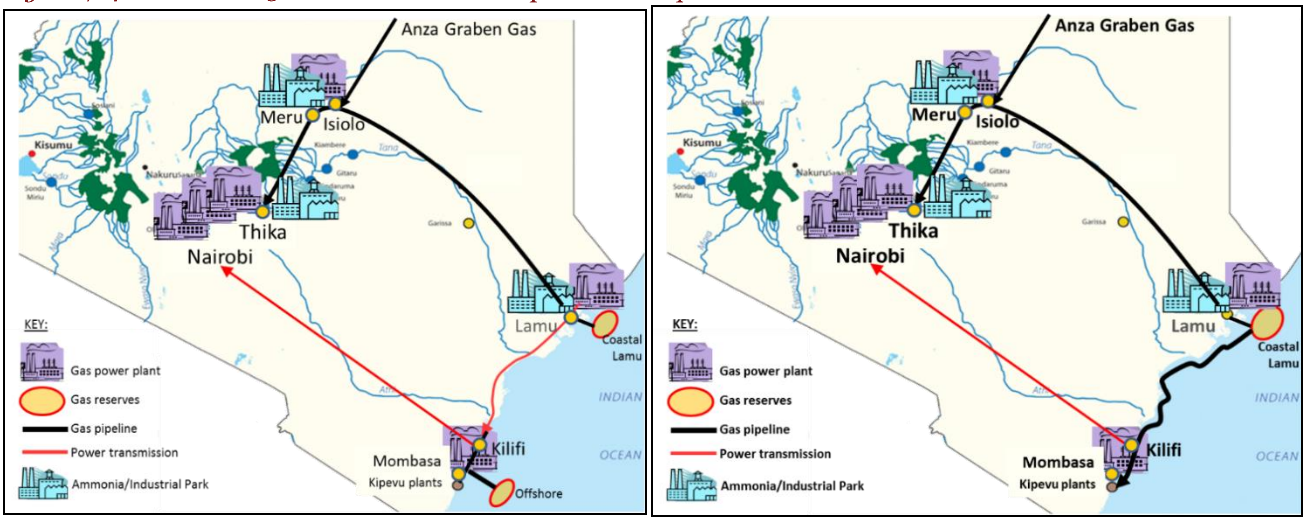

*Source: PwC Consortium*

## 7.5.5.3. Scenario 3: Coastal and inland plant development

In Scenario 3, we consider other options for gas pipeline development and domestic gas supply. With Coastal Lamu assumed to hold majority of gas resource potential in Kenya, a pipeline directly from Lamu towards the key gas demand area in Central Kenya is considered. Part of this could be developed as part of the LAPSSET corridor project. With gas resource also expected in the Anza Graben basin in Northern Kenya, a Lamu to Thika (close to Nairobi) pipeline allows for Anza gas connection midway, at Isiolo or Meru, providing another source of supply and hence more security as well as connection to the wider gas market for Anza producers. Gas supply from Anza may be already supplying new gas-fired power generation in Isiolo/Meru by then. Meru is expected to be a major industrial city with plans for iron and steel smelting, requiring 315 MW of power supply. Furthermore, being close to Central and Western Kenya, where the majority of agriculture is located, there is good potential for developing ammonia/fertilizer production in Isiolo or Meru. However, a pipeline to towards Nairobi would then allow increased gas supply from Anza supplying new projects closer to other demand centres.

As with Scenario 1, we have assumed gas-fired power generation at Mombasa or between Mombasa and Kilifi, with gas supply initially from LNG, later replaced by indigenous gas supply Offshore Mombasa (left) or from Coastal Lamu (right) if no gas is available Offshore Mombasa. As with Scenario 2, the development of gas pipelines allows additional gas-fired power generation to be developed closer to key demand centres inland in the future.

*Figure 7.40: Scenario 3: Coastal and inland plant development*



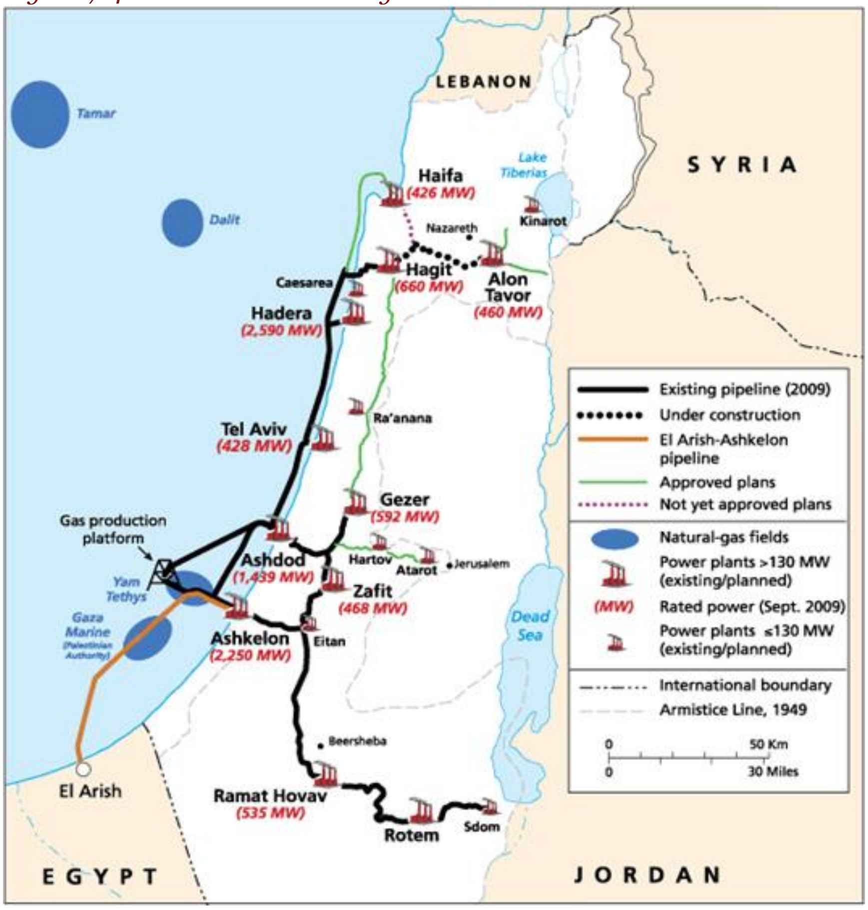

*Source: PwC Consortium*

## 7.5.5.4. Benchmarking the development of the Kenyan gas industry

Israel provides a useful benchmark for Kenya in considering the development of its national gas industry. The Israel natural gas sector is a relatively young industry, with first gas only arriving in 2004 from the shallow water developments followed by imported pipeline gas from Egypt in 2008. Further gas supplies were added in 2013 with production from the offshore Tamar gas field and there are prospects of further volumes from the recently discovered Leviathan field. Israel also has the ability to import LNG through a SBM system developed in 2012 in response to the curtailment of pipeline supplies from Egypt. Natural gas is now a primary source of energy, particularly in the power generation sector, replacing oil-fired power generation and through the development of new gas-fired power plants by State owned Israel Electric Corporation and IPPs. To meet the growing demand, the high pressure gas transmission network – originally set out in a Gas Master Plan by the Dutch gas company Gasunie in the late 1990's – has been extended and low pressure distribution networks are being developed to ensure delivery of gas to commercial and industrial consumers.

INGL, a Government owned company, was established in order to develop, construct, operate and maintain the natural gas delivery infrastructure in Israel. The Government granted a license to the company for 30 years (until 2034) to construct and operate the high pressure delivery system. However, its operating license restricts its participation in the buying and selling of gas (other than for system balancing purposes), so it is not in a position to distort the working of the market. However, this has led to other challenges such as how to implement Government strategy regarding small gas field development in the absence of a national champion. The initial investments of INGL were financed with equity provided by the State of Israel, and underpinned by long term transportation agreements signed with the state-owned power generation company Israel Electricity Company (IEC). All pipelines in Israel are set up on the basis of facilitating third party access, in accordance with the provisions of the Natural Gas Law. The existing gas transmission system is shown below.

*Figure 7.41: Gas transmission system in Israel*




*Source: PwC Consortium*

The basis of Israel's existing network remains the same as when the original Gas Master Plan was developed in the late 1990's, before the identity of the gas pipeline network developer/owner was known and before the confirmed discovery of economic quantities of indigenous gas reserves. The plan was developed with a good understanding of where natural gas was likely to be needed from a demand perspective, which would be largely driven by the requirements for power generation at least during the early years. The network outline then included a number of contingent options that allowed for the fact that gas supply may enter the system at a number of locations, either in the south or the north of the country. In addition, it was recognized that pipeline developments were often held up by consents and way-leave issues and local protests. Therefore, laying part of the transmission system just off the coast facilitated a more rapid transition to gas usage. After the system was developed to reach power plant locations, it was a relatively low cost and fast implementation process to then connect industrial consumers followed by smaller consumers via gas distribution franchises.

We might anticipate that the early years of the Kenyan gas market would follow a similar pattern, with power generation projects representing 'anchor loads' driving initial demand and influencing the rate and direction of pipeline system development. With initial gas supply through LNG imports and options for indigenous gas supply from several locations around the country (from the North and offshore from the East), Kenya should consider the development of gas infrastructure in an integrated manner so as to accommodate gas supply from various sources, at different times and also to enhance security of supply. As a first step, as was done in Israel, Kenya can consider laying a pipeline just offshore to enable early supplies from Lamu to replace or compliment LNG supply into Mombasa, and to then allow offshore fields to enter the onshore system at different locations with several options for supplying gas to Nairobi. Kenya must also consider whether it wants a state-owned entity to perform a similar role to INGL in Israel regarding the development and operation of the national network. Other options would include the development of the network by the private sector on a franchise or Build Own Operate Transfer ("BOOT") basis, which was the original intention of the Israeli Government before security issues led to the withdrawal of interest of international developers and investors.

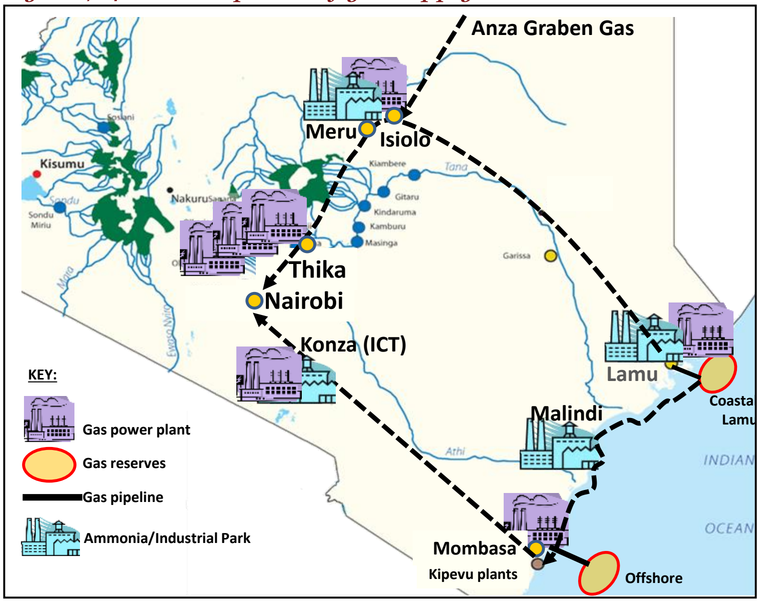
### *7.5.5.5. Conclusions*

We have considered three different scenarios for the development of the gas and gas to power market and gas infrastructure in Kenya. There is no right or wrong option and no scenario is considered better than the other, rather the selection should take into account all salient factors including those detailed in this Report. Each scenario aims to provide an understanding of the key drivers for the development of the gas market, including the current and future expectations of gas supply and gas demand locations. What is clear though is that the development of gas pipeline infrastructure for large scale projects will drive the uptake of gas consumption for smaller ones. Below we summarise some factors to consider in the development of local gas infrastructure.

- Planning the development of the gas industry will improve the outlook/reduce risk from an upstream investors' point of view, providing some assurance on being able to market gas locally, thereby potentially promoting further exploration and production investment. Additional exploration may then lead to discovery of larger gas resources and/or being able to make a case for LNG exports through aggregating several smaller resources.
- Creating an integrated pipeline system where supply can be sourced from several areas will increase security of gas supply and allows for a better functioning gas market. Security of gas supply is critical for the financing of any major gas use project, such as CCGTs.
- The cost of developing the gas pipeline network is typically much lower than the cost of the gas itself – assuming sufficient levels of demand in the different areas. Based on international norms, transportation costs contribute between 10-20% of end user tariffs.
- For new gas pipelines and gas user projects requiring these, then it is usually the case that the obtaining of wayleaves and consents for the gas pipeline lies on the critical path for project completion. Given that the costs associated with the consents process are relatively low compared to the construction costs, then it is recommended that the consents process for most likely pipeline routes are commenced as soon as possible.
- Developing an offshore gas pipeline is relatively easy to do as it limits the need for detailed consideration of the rights of way and land access issues. For onshore pipelines, it would be more optimal if the pipelines were developed along existing or planned corridors – such as the LAPSSET corridor for the pipeline to Isiolo/Meru, or along the existing rights of way for the oil existing and planned oil products pipeline from Mombasa to Nairobi, or new major road highways between Nairobi and cities upcountry. This simplifies and speeds up the process for obtaining consents and way leaves.

In the figure below we consider gas projects and gas infrastructure requirements from all three scenarios discussed above. Development of a fully integrated network with several sources of gas supply would be optimal, and such an approach has been adopted in many developed gas markets globally. If an economic justification can be made in the future to develop an LNG export project, then an integrated gas network would also allow gas monetisation through LNG from different supply sources, particularly if individual field sizes may be relatively small but can be aggregated.

*Figure 7.42: Development of gas supply network*




*Source: PwC Consortium*

We have focused on the development of gas-fired power generation, requiring around 3 Bcm/yr of gas supply in the Base Case and the potential production of ammonia/fertilizer for local use requiring up to 0.8 Bcm/yr gas supply. This is relatively small compared to gas use in other comparable countries and the potential for gas supply based on information and assumptions made on gas resources.

With the development of a more extensive gas supply network there are more options for where power plants and other gas projects can be developed. It may even allow for better optimisation on plant sizing and location depending on level of demand in different demand centres. Options for gas use in industry will depend on the development of these larger gas projects – or 'anchor loads' – and their own requirements for the development of gas supply infrastructure. Once larger projects and supply infrastructure are in place, gas use for industrial manufacturing or even in road transport can develop significantly, given availability of economically priced gas supply. Depending on Government policy, supply for smaller users could be controlled by a central buyer (either state-owned or awarded to private franchises through a tender process, similar to Israel, Northern Ireland, Greece and Nigeria) and sold to different consumers connected to the gas network. This approach has been successfully adopted in many developed gas markets, with unbundling and market liberalisation for these smaller consumers being introduced once a fully functioning gas market has been established. Consumer protection would need to be provided through effective industry regulation.

Kenyan gas demand for power generation, for gas products and for gas use in industry will inevitably depend on legislation and energy policy set by the Government. It will be important to consider gas pricing that is high enough to encourage production of gas resources and supply to the Kenyan market, and also competitive enough to facilitate the development of new gas projects and use by smaller consumers. Being able to supply gas at competitive prices to end users will require the development of an integrated gas supply network and this in turn will necessitate a coordinated approach between the Government and the different prospective key players in the gas sector, i.e. producers, transporters, and suppliers (who will need to consider the needs of their customers).

It is vital that the GoK should consider the development of the wider gas and energy industry rather than plan on a project-by-project basis. However, gas sector development is particularly challenging due to the need for full chain investment. With the development of the wider industry in mind a phased approach can be adopted, with updates to the Gas Master Plan as market and supply position change. Some of original routes may not be developed as exact market requirements change. However, considering consents and wayleaves for key gas pipeline routes from the start will provide assurance to upstream players and so facilitate the further investment in the sector that is required to instigate its development.

# 7.6. Gas Recommendations

Several key decisions need to be made by the Government of Kenya in the short term in order to provide a clear basis for the development of the gas sector in Kenya. Of these, the development of a coherent energy sector policy and the establishment of gas legislation and policy planning are critical, as discussed below.

**Establishing Energy Policy, Gas Legislation and Policy Planning:**

A starting point for the development of the gas sector is to have a coherent energy policy that takes into account the various needs across the oil, gas, power and wider energy sector. At present it is unclear how these interact and there may be inefficiencies in the development of energy infrastructure (i.e. co-development of 'energy corridors' for oil or gas pipelines, or power lines). Furthermore, there is a lack of an integrated approach to planning for power generation in general and, now that indigenous gas resources have been discovered, a role for gas in power generation should be seriously considered in preference to other forms of new power generation capacity.

Actively planning for the development of the local gas market will be key to providing assurance to potential gas producers that there will be a market for their gas in Kenya. Once potential gas producers are confident on this, then other mid and downstream investors can begin to consider investments.

An updated energy policy will also need to reflect the Government's encouragement of indigenous gas production by identifying an increased role for gas in the power generation sector. Kenya currently ranks as one of the most expensive countries for power supply due to a lack of reliable power generation, having to increasingly rely on costly diesel-fired power generation for baseload power supply and even more costly smaller emergency power producers for peak load power supply. With uncertainties around many other forms of power generation (e.g. low quality steam from geothermal, intermittent wind, unreliable hydro), gas-fired power generation could be key to providing baseload reliability of power supply. It is this reliable baseload power that will ultimately lead to reductions in power prices. Gas-fired power generation is lower cost, cleaner and more efficient than coal-fired power generation and should in most cases be considered in preference to coal – whether based on imports or indigenous resources. Furthermore, gas-fired power generation can be developed more expeditiously than most other options (in around 2 years) and can therefore meet any expected shortfalls in short-medium term power generation capacity that may arise if plans for other forms of power generation do not materialize in full. It will be important to consider the role of baseload gas power generation in terms of Power Master Planning. Hence, a Power Master Plan should be well aligned with options and recommendations for the Gas Master Plan.

Primary legislation should include developing and passing a specific Gas Law and establishing a gas industry regulator and regulatory framework. Secondary legislation will include considering and drafting operating license agreements and designing the regulatory framework, including the development of a network code and tariff setting policies. Having legislation in place can then facilitate investment in developing the local gas industry through international tender processes and/or direct private investment. A legislative and regulatory framework will also be a prerequisite for raising finance and attaining FID.

The Government will need to agree specific gas terms in upstream production licenses and terms for supplying gas. Currently, Kenyan production licenses contemplate oil reserves and these will require adjustment in the event of significant gas finds. As mentioned before, when discussing the development of individual gas projects with developers, it will be important to consider the development of the wider industry from the onset and not encourage project development on a stand-alone basis.

**Gas Resource:**

**Issue:** Despite recent high levels of exploration activity and a number of gas discoveries, Kenya is still very much a frontier exploration play. Gas resource estimates are currently based on limited amounts of information from a limited number of licensing blocks that are in the early stages of development, with many others yet to begin detailed exploration activity. It will be some years before the level of exploration in Kenya reaches a point where the potential gas resource can be regarded as firm, and a full Gas Master Plan can be developed.

**Recommendation(s):** (i) GoK should update the information on gas resource estimates provided in this Study as more information becomes available from upstream players from further exploration and extended well testing. This includes receiving technical reports from oil companies operating within Kenya as per the requirements in the PSC, if and when these are available. (ii) GoK should also look to undertake a separate detailed geological study on gas resource potential. This will enable a more complete picture to be developed of reserves and future potential production as the operators' technical data grows. (iii) GoK should look to promote exploration activity as much as possible through conducive license terms in these very early stages of exploration. This will help provide better quality information as well as prove up additional resources.

**Gas Demand:**

**Issue:** Unlike countries such as Tanzania, Mozambique, Nigeria and Algeria, based on the information currently available, Kenya does not have sufficient amounts of gas resource to consider developing an LNG export project. With pipeline exports also being limited (from a demand perspective), current options for monetizing gas resource potentially available is to supply the local market, with gas use in power generation being the only feasible large scale option. However, up until now, Kenya has not considered a major role for gas-fired power generation in its power mix, and a strong case should be made given that gas can provide more reliable baseload power generation (unlike renewables) and is cleaner, cheaper and more efficient than oil or coal-fired power generation. It can also be developed much faster than other forms of power generation and at a lower capital cost per MW of capacity installed.

**Recommendation:** GoK needs to undertake a detailed Power Sector Master Plan in addition to the Least Cost Power Development Plan which considers the role for gas-fired power generation in relation to other forms of power generation. Part of this plan should consider the likelihood of realizing targets for significant amounts of geothermal power generation and to produce a more detail power demand forecast which will better inform shorter term programs such as the addition of 5000+MW by 2017 announced in September 2013. Better planning will help alleviate risks of capacity oversupply (as is currently the case) and the development of sub-optimal power generation capacity.

**Gas Supply:**

**Issue:** Given uncertainties around the role for gas in power generation and given that upstream players are still at early stages of exploration, we assume gas supply can only come online post-2020. However, with no existing gas market in Kenya it will be difficult for upstream players to justify making further investment to produce fields without being given more assurance on gas demand and pricing. If no assurance is provided, this will eventually lead to a lack of investment in the upstream with developments only focused on potential exports – as has been the case in other gas rich countries in Africa to the detriment of the local market.

**Recommendation**: GoK must actively promote the development of the local gas market, thereby providing exploration companies with more assurance with regard to gas monetisation for their fields. Planning the development of the gas industry and forming Gas Policy (within the context of a broader Energy Policy) will improve the outlook/reduce risk from an upstream investors' point of view, thereby promoting further exploration and production activities, which may then lead to discovery of more gas for the Kenyan market which could eventually be sufficient for exports.

**LNG Imports:**

**Issue:** Despite the Government actively promoting the role for gas in the local market, there may still be a stand-off between investment by upstream producers to develop indigenous gas resources without security of gas offtake and investment by gas-fired power plant developers without firm security of gas supply. This is not helped by the fact that it would a number of more years to bring indigenous gas supply online (assumed to be at least 3-5 years) compared to the time required to develop a gas-fired power plant (typically 2 years).

**Recommendation**: Developing gas-fired power plants supplied initially through LNG imports in the short term (up to 5 years) can help alleviate this problem. Upstream producers can be given assurance that indigenous gas supply will be used to replace LNG supply once it can come onstream. In considering the LNG to power project, the possibility of siting the power plants closer to Nairobi and developing a gas pipeline from the LNG import point to the power plants should also be considered. The potential timing and requirement of this project is still very uncertain and would need to be considered taking into account more information on the timing of potential gas supply and the development of other forms of power generation and energy transmission. Nevertheless, LNG to power should be considered in preference to coal-fired power generation, not only to help promote the development of the local gas industry, but also because it is just as competitive and a lot cleaner and more efficient than coal.

**Developing Gas-fired power projects:**

**Issue:** Gas sector development is particularly challenging due to the need for full chain investment. Given the lack of an existing market and given the potential standoff between investment from upstream producers and by power plant developers, there is a risk that upstream producers seek Government approval to develop their own power generation options to monetize gas resources. This is likely to lead to a sub-optimal development of the gas industry on a project by project basis.

**Recommendation**: It is vital that the GoK consider the development of the wider gas and energy industry rather than plan on a project-by-project basis. This would allow for the development of gas infrastructure rather than just power transmission from power plants located close to gas resources. The development of gas infrastructure has several key benefits:

- There are more options for where gas-fired power plants and other large gas projects can be developed.
- Once larger projects are in place, gas use by smaller users can develop and in time make up a large share of overall gas demand.
- Creating an integrated pipeline system where supply can be sourced from several areas will increase security of gas supply and allows for a better functioning gas market.
- If there is an integrated gas system in which gas can be supplied to multiple offtake points, this reduces the risk to upstream producer.

A starting point for creating an integrated network is to create a detailed plan for different supply and demand nodes. It is then usually the case that requirement for wayleaves and consents for the gas pipeline lies on the critical path. Given that the costs associated with the consents process are relatively low compared to the construction costs, it is recommended that the consents process for the most likely pipeline routes are commenced as soon as possible. Planning the development of a gas network will provide assurance to upstream producers on the development of a local market for gas and increased investment.

**Private sector participation:**

**Issue:** Given the project risks associated with major infrastructure development, private sector participation will allow the transfer / sharing of risks from the Government to the private sector. The analysis carried out under Chapter 8 demonstrates the benefits that would emanate vis-à-vis the implementation of projects with private sector involvement, i.e. project financing strength through ring fenced structures and optimal risk allocation that will enhance project bankability.

**Recommendation:** It is recommended that the government execute the identified gas monetization options through a PPP structure, where ring fenced project finance will attract a mix of concessional, DFI and some commercial funding. In addition to adequate risk allocation, PPP are also considered more affordable to the government and demonstrate value for money to the public sector. Under such a framework, it is still important to have government support in the form of either a Sovereign Guarantee or a GoK support letter, in the event of an offtake default.

## 7.7. Gas Experience in Other Countries

In order to successfully develop a greenfield gas industry, be it from gas imports or based on indigenous supply, the Government of any country must always consider two key aspects from early stages of Gas Master Planning:

1) Supply and Demand: the need for economic gas pricing and security of gas supply and offtake
2) Infrastructure: the need for gas infrastructure and creation of competition

Many countries have failed on one or both of these aspects and have therefore not been able to grow their gas markets as planned, having to continue to rely on alternatives in the established but more expensive oil industry.

### 7.7.1.1. Supply and Demand: the need for economic gas pricing and security of gas supply and offtake

Gas use will generally be cheaper, cleaner and more efficient than alternative fuels. Hence the need for economic pricing would be supply driven rather than demand driven, i.e. domestic prices should be high enough in order to promote more gas supply from indigenous gas production or through imports, without the need for subsidies from the Government. In developed gas markets, gas is commonly priced against alternative fuels in different industry sectors (mainly oil products) or in relation to gas market prices where prices are driven by gas supply and demand fundamentals. Developing gas markets often use fixed pricing, which risks being out of the market and receives strong opposition when increases are contemplated or attempted. Nevertheless, if set initially at the right level and well regulated, fixed gas pricing is easier to understand and can work well. Many countries with indigenous reserves have set these initially at very low levels in the hope of promoting gas use and growing demand, only to realise that supply at these prices is not sustainable but difficult to raise.

In order to avoid the issues faced by countries such as India and Malaysia, Kenya should determine a sound and transparent methodology for gas pricing from the onset. With gas supply initially expected to come from imports of LNG, gas prices must reflect international prices and can then be potentially reduced as indigenous production is brought online, bearing in mind that prices still need to be high enough prices to justify domestic production and encourage continued exploration. Prices may not need to be sustained at international price parity as smaller indigenous gas producers may not have an option but to supply domestically. Subsidising gas prices initially is not sustainable and price increases are likely to be challenged. Unlike India and Malaysia, gas prices in Israel are determined through commercial negotiations between buyers and sellers. With several supplying companies, all with access to gas infrastructure, buyers are free to choose their supplier, thereby keeping prices and other supply terms competitive and ensuring security of supply. The key therefore appears to be developing accessible gas infrastructure to enable multiple players to reach the market.

### 7.7.1.2. Infrastructure: the need for gas infrastructure and creation of competition

Given the right pricing, the development of gas infrastructure (mainly gas pipelines) will be required to meet demand in different locations. The Government's role in this is critical in order to consider a more holistic view of developing the industry as opposed to one project at a time. Infrastructure will initially and mainly be required for supplying major 'anchor' gas projects, such as a large power plant. Industrial demand will take time to develop once larger projects are in place, but if this is anticipated and planned for earlier on, it not only provides assurance for smaller projects but also optimises infrastructure development plans, costing and pricing. Opening up infrastructure access for third parties will be important in providing access to supply and creating competition amongst suppliers. Governments have developed major gas infrastructure based on revenues from other sectors or through loans. As infrastructure projects are generally low risk and hence receive regulated returns, seeking private sector investment should not be too challenging. The Government's role in development is more important from a planning and regulation perspective.

The Kenyan Government would need to have a large role in the planning and development of gas infrastructure. As Kenya is not expected to be as large a gas/LNG exporter as Nigeria, domestic supply obligations for export projects may be small. With the likelihood of potential indigenous gas production to be supplied domestically, domestic gas pricing at economical price levels will be more critical. Gas infrastructure costs should only make up a small portion of the overall end user price. If gas prices are set as such in Kenya, there are considerable benefits to be had in the development of smaller projects in the industrial sector in addition to the larger projects which are expected. With the majority of the gas reserves expected to be located in coastal Lamu, and with a gas demand from the planned conversions and large scale power plant(s) in Mombasa, Kenya can benefit from fast track development of an offshore gas pipeline, as Israel has done.

### *7.7.1.3. Summary of Observations - Learning and implications for Kenya (Gas)*

We discuss the key points arising from our analysis in more detail and provide some lessons from the benchmark countries below:

*Table 7.19: Summary of key midstream and downstream learning points (Gas)*

| Learning Point | Implications for Kenya |
|---|---|
| Supply and Demand: the need for economic gas pricing and security of gas supply and off take | Gas use will generally be cheaper, cleaner and more efficient than alternative fuels. Hence the need for economic pricing would be supply driven rather than demand driven, i.e. domestic prices should be high enough in order to promote more gas supply from indigenous gas production or through imports, without the need for subsidies from the Government. In developed gas markets, gas is commonly priced against alternative fuels in different industry sectors (mainly oil products) or in relation to gas market prices where prices are driven by gas supply and demand fundamentals. Developing gas markets often use fixed pricing, which risks being out of the market and receives strong opposition when increases are contemplated or attempted. Nevertheless, if set initially at the right level and well regulated, fixed gas pricing is easier to understand and can work well. Many countries with indigenous reserves have set these initially at very low levels in the hope of promoting gas use and growing demand, only to realise that supply at these prices is not sustainable but difficult to raise.<br><br>Gas prices in Malaysia are heavily subsidised at around US$5/MMBtu, with 50% of gas demand coming from power generation and 30% from industry. Since 2010 the Government has been planning to remove gas subsidies but has made little progress to date, opting for political gain at the cost of the international development of its national oil company, PETRONAS. Removing subsidies is also important in order to promote more gas production and supply to the domestic market. Malaysia has recently had to turn to imports of LNG, paying international gas prices of around three times the subsidised domestic price. Pakistan is also facing the same issue. Nevertheless, some industrial players have agreed to pay such prices in order to secure gas supply. The Malaysian Government's attempt to increase gas production and supply domestically thus far has been to reduce the petroleum income tax from 38% to 25% and an increase in the reimbursement for a company's original investment from 70% to 100% for production from smaller, deeper and more remote fields.<br><br>India has experienced similar issues to Malaysia, with low domestic gas prices inhibiting the development of indigenous gas production. Prices are currently administered for gas production at US$4.2/MMBtu increased from US$1.8/MMBtu in 2010. Transport costs and prices to end users are also regulated and are determined on a cost plus basis. Administered prices are proposed to be increased to US$8.4/MMBtu in 2014 with indexation to international prices with the aim of eventually reaching international price parity. However, there has been strong opposition against price increases and the Government is currently reviewing its options. With the lack of indigenous |

| Learning Point | Implications for Kenya |
|---|---|
| | production and uncertainty as to whether this may change, India increasingly has to rely on internationally priced LNG imports. LNG imports currently account for 35% of total consumption and are largely supplied to industry and fertiliser production, where it is cheaper than oil product alternatives. If LNG is required to meet rising demand in other sectors, domestic prices would have to triple to justify supply. In any case, prices have to be increased in order to encourage more indigenous production and curb the increasing dependence on more costly LNG imports.<br><br>In order to avoid the issues faced by India and Malaysia, Kenya should determine a sound and transparent methodology for gas pricing from the outset. With gas supply initially expected to come from imports of LNG, gas prices must reflect international prices and can then be reduced as indigenous production is brought online with a lower associated cost, bearing in mind that prices still need to be high enough prices to justify domestic supply and encourage continued exploration and production. Prices may not need to be sustained at international price parity as smaller indigenous gas producers may not have an option but to supply domestically. Increasing demand should lead to more competition between indigenous suppliers if the regulatory environment is correctly set, thereby ensuring that gas prices remain competitive. Subsidising gas prices initially is not sustainable and price increases are likely to be challenged. Unlike India and Malaysia, gas prices in Israel are determined through commercial negotiations between buyers and sellers. With several supplying companies, all with access to gas infrastructure, buyers are free to choose their supplier, thereby keeping prices and other supply terms competitive and ensuring security of supply. |
| Infrastructure: the need for gas infrastructure and creation of competition | Given the right pricing, the development of gas infrastructure (mainly gas pipelines) will be required to meet demand in different locations. The Government's role in this is critical in order to consider a more holistic view of developing the industry as opposed to one project at a time. Infrastructure will initially and mainly be required for supplying major 'anchor' gas projects, such as a large power plant. Industrial demand will take time to develop once larger projects are in place, but if this is anticipated and planned for earlier on, it not only provides assurance for smaller projects but also optimises infrastructure development plans, costing and pricing. Opening up infrastructure access for third parties will be important in providing access to supply and creating competition amongst suppliers. Governments have developed major gas infrastructure based on revenues from other sectors or through loans. As infrastructure projects are generally low risk and hence received regulated returns, seeking private sector investment should not be too challenging. The Government's role in the development is more important from a planning and regulation perspective.<br><br>Despite having sub-optimal gas pricing, India and Malaysia have managed to develop a significant gas pipeline transmission and distribution network. This has been mainly through state-owned companies, which own many other assets and are credit worthy, and can therefore easily raise finance for the development of relatively low risk gas infrastructure. Pipeline tariffs are regulated and aim to provide the companies with a 'reasonable' rate of return on total costs. India has also developed Access Codes requiring one third of the capacity in both gas pipelines and LNG import terminals to be made available to third-parties with the tariffs for third party users also being subject to regulation. |

| Learning Point | Implications for Kenya |
|---|---|
| | Similar success in gas infrastructure development has been seen in Turkey, Trinidad and Israel. In Turkey, state owned BOTAS enjoyed monopoly rights on natural gas import, distribution, sales and pricing for over ten years up until 2001. Over this time the market was well developed with supply mainly through imports and end user prices tracking pipeline import prices. In 2001, the market was liberalized, with BOTAs maintaining control of LNG imports, gas transmission and storage facilities. There are currently also 42 wholesaling companies and 63 distribution companies in the country. In Trinidad, state-owned NGC was tasked with the promotion of the natural gas industry and was given the monopoly over the purchasing, selling and distribution of natural gas to industrial and commercial consumers. NGC quickly developed and operated a gas transmission network to supply cheap associated gas to power stations and then to petrochemical plants around the country. NGC went on to lead gas supply negotiations with operators for on sale to domestic customers. However, the market in Trinidad is small, and with significant revenues from a history of oil production as backing, the development of a gas industry was much easier to do.<br><br>In Israel the Government had a clear picture of the likely demand centres which was largely based on gas-fired power generation projects. After the system was developed to reach these power plant locations, it was a relatively low cost and a fast implementation process to then connect industrial consumers followed by smaller consumers via gas distribution franchises. The Government was also clear from the outset that the gas industry should work as far as possible on a competitive basis. INGL was given the monopoly on gas transportation but was not allowed to purchase or supply gas itself. Buyers and seller were given access to INGL's transmission pipeline for a regulated fee.<br><br>Nigeria, despite holding some of the world's largest reserves of natural gas, has thus far failed to develop a domestic natural gas industry. With very low domestic gas prices of US$1/MMBtu, planned to be increased to US$2/MMBtu, not many gas producers are willing to supply the domestic market. However, with the introduction of plans for Domestic Supply Obligation Policy as part of the 2008 Gas Master Plan, a predetermined amount of gas supply should be available from gas producers. This policy is expected to be included in the long-awaited Petroleum Industry Bill (PIB). Gas supply aside, Nigeria's major problems also lie in a lack of gas infrastructure, to the extent that gas-fired power plants have been developed and have had to be mothballed or delayed coming online due to a lack of gas supply. The Government did little to secure the development of gas infrastructure and is now having to rectify this. Fortunately, the development of gas infrastructure sits outside the controversial PIB and is currently underway, with the hopes that the PIB will be passed and gas will start to be supplied upon completion. |

*Source: PwC Consortium Analysis*

# *Financing Oil and Gas Development*

# 8. Financing Oil and Gas Development

This section is designed to assess various funding structures that could be utilized for financing solutions in the development of oil and gas commercialisation options as identified earlier. In setting the scene, we analyse the current investment climate in Kenya in order to evaluate the attractiveness of the country as an investment destination.

## 8.1. Investment Climate in Kenya

The recent developments in the oil and gas sector alongside other natural resource discoveries across Kenya have opened discussions on the potential for the country being resource rich. This and the underdeveloped infrastructure, including significant technological gaps have for years created room for investments in the country.

The ability to attract investment is however anchored on the ease of doing business in Kenya. The Government has implemented reforms across various sectors in the economy with the ultimate objective of encouraging investment into the country, enabling a more favourable investment climate. These actions include:

- **Constitution of Kenya (2010):** improved contract and property rights enforcement via the establishment of an independent judiciary and the National Land Commission.

- **Public Private Partnership (PPP) Act (2013):** establishment of a legal framework to allow private sector participation in Government projects.

- **Regulatory Reforms – Licensing Act (2007):** simplification and elimination of licenses in addition to the reduction in the number of licences required to set up a business, establishment of a Business Regulatory Unit within the Ministry of Finance to continue the deregulation process, and a national e-Registry to ease business licence processes and transparency.

- **Avoidance of double taxation treaties (DTA):** agreements with the following countries have been established- Norway, U.K, Germany, India, Canada, Sweden Denmark, Zambia, France, Mauritius (not ratified) and EAC (not ratified) amongst others.

- **Incentives:**

  - Investment allowance on capital expenditure for manufacturing machinery and buildings, and hotel buildings= 100% reduction in Nairobi, Mombasa and Kisumu. 150% in other towns.
  - Import duty waiver on capital goods for investments above US$ 70,000 and with approval of the Cabinet Secretary in the Ministry of Finance.

According to the World Bank June 2014 databank index of Doing Business, Kenya ranks 136$^{th}$ globally (out of 183 economies), improving one position from the previous year. This increase can be attributed to an increase in two factors: taxation – whose ranking increased from 146$^{th}$ to 102$^{nd}$ , and resolving insolvency – whose ranking increased from 138$^{th}$ to 134$^{th}$. Factors whose rankings remained unchanged included the ease of getting electricity and enforcing contracts.

In assessing the state of Kenya's investment climate for oil and gas, it is important to note the recent developments in the sector globally, which will significantly impact the success of the local sector. For instance the recent discoveries of Shale Gas in the United States has created a major competitor for oil producing countries. Kenya therefore needs to be weary of the investment framework they create to ensure it is favourable and will attract consistent investment despite global changes in supply and demand. The recent decrease in oil prices will also be a factor, as persistence of the price at levels below US$ 60 per barrel will result in many exploration companies reviewing their budgets, particularly for activities in marginal regions with limited proven resources.

## 8.2. Fiscal and regulatory framework

### Upstream Legal and Regulatory Framework

Given Kenya is still in the exploration phase of oil and gas, the entry point for most new oil and gas entrants is through the upstream sector. We summarise below the major elements within the investment framework that is currently in existence.

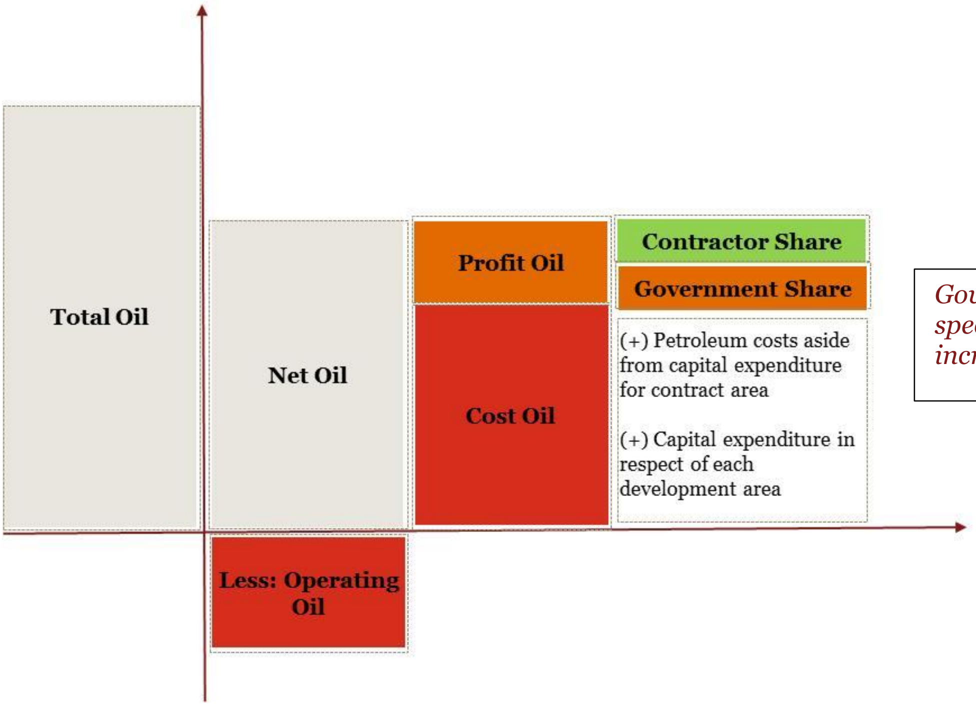
*Table 8.1: Basics mechanisms of the PSC*

| | |
|---|---|
| **Exploration activities are bound within the framework of a production sharing contract. The table below highlights the basic mechanisms of this contract:** | |
| **1** | The contractor (i.e. the upstream player) bears 100% of the Exploration, Appraisal, Development and Operating costs. |
| **2** | The contractor is remunerated from sales of:<br>• 'Cost oil/gas' allowing the recovery of some or all of his past costs<br>• 'Profit oil/gas' allowing a return on the investment risk |
| **3** | Government take is through<br>• Share of profit oil/gas<br>• Taxes and bonuses to host Government |
| **4** | • State taxes paid out of Contractor profit |

*Source: PwC Consortium Analysis*

The diagram below demonstrates the cash flow from the production sharing contracts:

*Figure 8.1: Cashflows from production sharing contracts*




*Government and Contractor Share is specific to each PSC and based on increments of profit oil.*

*Source:PwC Consortium Analysis*

## *Farm in / out transactions*

Exploration companies generally raise financing for funding petroleum operations through farm in/out transactions. There are however a number of taxes upstream players are required to pay when farming in/out of an oil block.

- Total gains to a farmer will be considered business income net of expense and subject to a corporate tax rate of 30% for residents and 37.5% for non-residents.
- An amount paid by an entity acquiring an interest in a block will be classified as exploration / development expenditure and is therefore fully tax deductible.
- A farm in / out is considered an assignment of a right and as such a supply of a service which is subject to 16% Value Added Tax.

The Kenya Revenue Authority is currently streamlining the existing framework with upstream players to ensure effective implementation of the Finance Act 2014 which included a re-write of the Ninth Schedule of the Income Tax Act that outlines taxation of extractive industries. It is important for the Government to clarify any gray areas identified within the law where clarification is sought by the private sector.

The framework within which the upstream sector operates needs to be assessed to determine whether foreign and local investors deem it an investor friendly framework, especially given the high risk nature of exploration activities and that access to financing is minimal. As part of the upstream regulatory framework, the proposed Upstream Petroleum Authority will now need to develop a crude pipeline tariff approach and gas pricing methodology.

**Midstream and Downstream Legal and Regulatory Framework**

The MoEP oversees a monthly open tendering system whereby licensed oil marketing companies bid to import product into the country at the lowest price. The tendered quantities are the aggregate of the demands specified by all the companies. The winning company then onsells the imported product to other OMCs at the winning bid price plus industry agreed cost build up parameters to land the product into the country. Therefore all licensed importers have the same landed cost of product.

In the monthly petroleum retail price calculation ERC then considers the actual landed cost of product in addition to product distribution costs across the country and company margins when determining the pump price at which OMCs will sell product to the public.

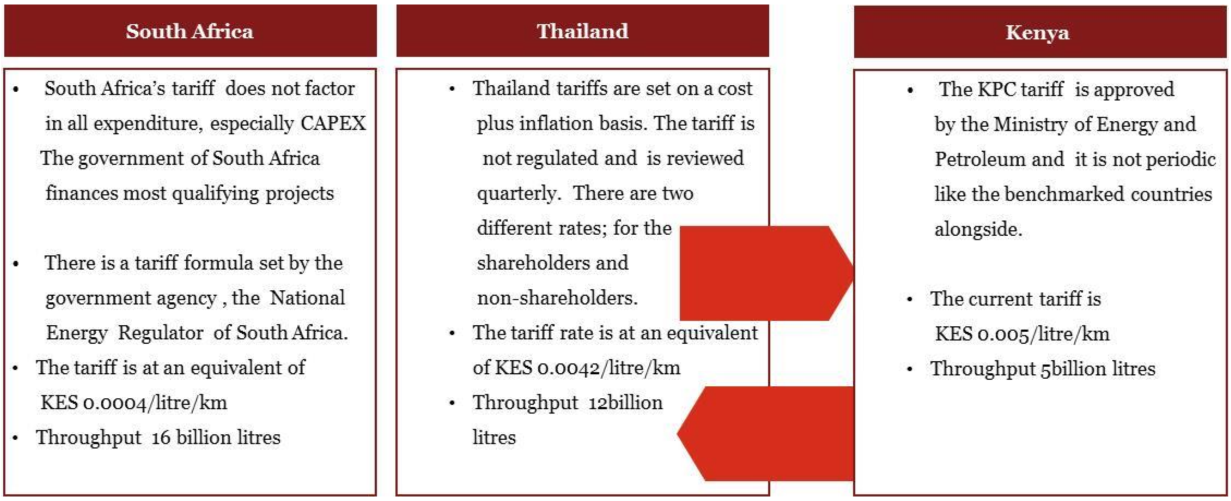
The midstream sector, dominated by the KPC system, on the other hand determines the required tariff for operations and seeks approval from the ERC. The recent proposed changes to the legal and regulatory framework in Kenya seek to segregate regulation of the upstream, midstream and downstream sectors. This will improve on the transparency and efficiency of the various value chains of the oil and gas sector. The main gap remains with developing a gas policy to facilitate gas monetization in Kenya.

## 8.3. Tariff setting and pricing

**Downstream Pipeline and Storage Tariff**

The KPC downstream tariff is currently approved by the MoEP. The diagram below presents an illustration of a comparative analysis of the rationale behind Kenya's tariff vis-à-vis peer comparisons. At KES 0.005/litre/km for a throughput of 5b litres, a detailed tariff study needs to be carried out by GoK to assess the affordability and justification of the high nature of this tariff compared to KES 0.0004/litre/km for a throughput of 16b litres in South Africa and KES 0.0042/litre/km for a throughput of 12b litres in Thailand.

*Figure 8.2: Tariff comparative analysis*




*Source: PwC Consortium Analysis*

**Crude Pipeline**

The revenue streams for any project are critical to determining how attractive a project is to investors. We discuss key considerations the crude pipeline tariff should envelop and an optimal gas pricing mechanism to ensure a desirable return to the project sponsors. The analysis presented in this discussion is based on the identified oil commercialisation and gas monetisation options.

There is currently no crude pipeline tariff that has been determined by the GoK. It is worth noting however, the Governments of Kenya, Uganda and Rwanda are jointly undertaking a feasibility study for the transnational crude pipeline. The scope of this study includes providing guidance to the Kenyan and Ugandan Governments to help them determine an optimal tariff for the transportation of crude from Lake Albert and Lake Turkana to the coastal region of Kenya.

Given the heavy capital requirement for the development of the crude pipeline, it would be prudent to adopt a 'cost-reflective' tariff as illustrated below. This Study does not propose a tariff methodology per se, but rather demonstrates the various components that should be considered when developing the tariff.

*Table 8.2: Components to consider in developing a tariff*

| Allowable revenue for crude pipeline | |
|---|---|
| Regulatory Asset Base | Value of the asset upon which a return can be earned. (less accumulated depreciation + net working capital) |
| Operating and maintenance expenses | Salaries and wages, utilities, materials and supplies, maintenance and repairs. |
| Depreciation | Asset depreciation for each period |
| Revenue required for debt service | Periodical debt service requirements for construction of the asset |
| Taxes | Income tax allowance |
| Reasonable return | A margin over and above revenue net of costs |

*Source: PwC Consortium Analysis*

To ensure the crude pipeline tariff is affordable, the regulatory authorities would need to ensure the margin above the allowable revenue as described above is reasonable and not overstated.

**Gas Pricing**

Kenyan legislation does not have a Gas Policy. There is therefore no regulation on gas pricing/tariff setting, which would be critical to determining the financial viability of any of the gas monetization options. This Study demonstrates (including as part of the financial modelling exercise) a gas pricing methodology which determines a tariff for each monetization option.

*Netback tariff methodology* - tariffs are determined at the plant gate (i.e. the inlet for gas supply to the plant), deducting unit costs of production from assumed market prices, and providing an indication of the maximum feedgas price (in US$/MMBtu) that the project can afford in to make an assumed rate of return. Generally:

Netback price = Market price – Cost of Production

The cost of production should take into consideration financing costs, operating expenses and capital expenditure.

## 8.4. The funding Gap

As outlined in the Overview and Major Issues Chapter, the total funding gap for infrastructure projects that Kenya is planning to implement is somewhere in the range of US$ 40b, in the period up to 2020. Total costs amount to approximately US$ 65b whilst available funds during this period are estimated to be about US$ 25b. Details of this have been presented earlier, needless to say, the GoK needs to leverage and draw upon the private sector if it is to successfully implement its infrastructure plans whilst keeping a prudent fiscal and debt management policy in place. It is difficult, based upon the available data, to decipher the costs relating to the development of the oil and gas sector as a proportion of the amounts referred to above. Energy investments are listed as one of the areas in the GoK estimates, however, the oil and gas sector is not broken down in terms of data. We have outlined our estimates of total infrastructure investment required in the oil and gas sector earlier, and we present this information below.

Based upon preliminary high level benchmark estimates as detailed below, the total cost of the infrastructure requirement for the oil and gas sector, excluding the costs of upstream exploration and field development, ranges from between US$ 29b and US$ 32b, if a new refinery and an LNG production plant are developed. The scale of financing required by the sector is substantial in the context of GoK's other infrastructure and budgetary commitments, and in order to maximise the full potential of the sector, GoK needs to actively seek and promote private sector investments for the oil and gas sector.

*Table 8.3: Oil and gas infrastructure cost*

| | Project | Estimated Base Case Capex (US$ m) |
|---|---|---|
| 1. | Crude Pipeline 1 - Common Pipeline Phase 1 | 2,600 |
| 2. | Crude Pipeline 2 - Common Pipeline Phase 2 | 1,800 |
| 3. | Crude Pipeline 3 (East Rift Connector to Lokichar) | 220 |
| 4. | Crude Pipeline 4 (Lake Albert connector to Lokichar) | 1,800 |
| **5.** | **Mombasa-Nairobi Product Pipeline** | |
| *5.a* | *Line 5* | 490 |
| *5.b* | *Line 5 upgrade* | 100 |
| *5.c* | *Line X (c. 2040)* | 368 |
| **6** | **Nairobi - Nakuru Product Pipeline** | |
| *6.a* | *Line 4 upgrade* | 25 |
| *6.b* | *Line 4 upgrade* | 25 |
| **7.** | Sinendet - Kisumu Line 7 | 148 |
| **8.** | Eldoret-Kampala (Uganda) Kigali (Rwanda) | 450 |
| **9.** | Refinery | 1,700 – 5,000* |

| | Project | Estimated Base Case Capex (US$ m) |
|---|---|---|
| 10. | Storage Conversion/Upgrade | 347 |
| 11. | Storage New Build Programme | 656 |
| 12. | 800MW CCGT plant | 875** |
| 13. | 10 mtpa 2 train LNG facility | 14,000 |
| 14. | 1 mtpa Ammonia plant | 1,200 |
| 15. | 1 mtpa Methanol plant | 1,200 |
| 16. | 5 Bcm/yr Gas pipeline (Lamu to Mombasa offshore) | 780 |
| | | |
| | **Total potential Oil and Gas Infrastructure cost (with LNG production plant and Refinery)** | **28,784 - 32,084** |
| | **Total potential Oil and Gas Infrastructure cost (without LNG production plant and Refinery)** | **14,784 -18,084** |

** Depending on complexity,*

*** Cost for single plant. Multiple plants are likely to be developed*

*Source: PwC Consortium Analysis*

Kenya's midstream and downstream sector is more advanced but is characterized by infrastructure that is aged and in need of upgrading, both in technical specification and capacity. Furthermore the successful production of oil will require additional infrastructure, in particular the crude oil pipeline and potentially gas infrastructure. Given GoK's infrastructure development commitments, and the need to balance provision of social services and infrastructure development within constrained resources, it is unlikely GoK will be able to fund the entire required infrastructure through public funds. Involvement of the private sector, whether directly or through Public Private Partnerships (PPPs) would likely be an optimal option for required infrastructure development. PPPs /Project Finance structures will also allow GoK to share and transfer the risks involved in developing and operating these projects.

## *8.5. Closing the funding gap – potential sources and financing options*

According to the African Development Bank (AfDB), Kenya requires US$ 4b per year to fund infrastructure development, in the form of roads, energy, water and other developments. GoK has issued infrastructure bonds as a means of partially funding this development gap. More recently, Kenya sought financing for capital projects from the international markets, by raising a US$ 2b Eurobond in 5 year and 10 year notes. GoK is seeking to raise further sovereign bonds targeting Kenyans in the Diaspora, Islamic interest free bonds ("Sukuks") and Yen denominated bonds. With relevance to this Study, and based on the magnitude of capital required for the development of the oil and gas sector, it is probable that investors in development of the sector will likely seek funding from DFIs, multinational commercial banks or via infrastructure bonds.

Despite the evident growth and strength of the country's banking sector as highlighted in Chapter 3, the required funding for significant capital intensive projects may not fall within the lending capacity of the local market. These types of projects generally seek US dollar denominated loans, as capital expenditure, operating costs and revenues are usually denominated in this or other hard currency. The local commercial bank market, however, has limited hard currency reserves and as such the financing required for large capital projects, in terms of quantum, tenor and pricing would largely be unavailable locally. The larger indigenous Kenyan commercial banks would be limited to ticket sizes of not more than US$ 20m in Dollar denominated facilities, and even if lending was extended, tenors would be short. International financial institutions operating in Kenya would largely rely on lines or cofinancing from their parent banks. This scenario has been one of the main drivers of the push by international banks without a local presence opening representative offices in the country, allowing them to source for deals and have their parent banks then finance the projects.

DFI funding would be attractive to the sector as it would be tied to the local economic development of the country, bearing in mind social and developmental considerations. It is positive to note that with the requirement for NEMA approval for all projects in Kenya, there is a drive towards most mega projects complying with IFC or AfDB environmental standards, which makes these attractive to the DFIs. DFIs may also be able to attract a concessional tranche to projects, especially if the local economic and social developmental factor is high but with a low level of bankability based on the required project structure. DFI funding for mega projects normally requires a sovereign guarantee to be provided by Government.

Commercial bank funding, which is increasingly competitive with DFI funding in terms of pricing, and may be made more attractive when syndicated with a DFI portion, is increasingly available for mega projects from international institutions, with pricing being pegged on perception of project and country risks, and availability of sovereign guarantees.

Infrastructure bonds to finance mega projects in the country, whether listed in Kenya (although unlikely due to the limited availability of hard currency) or on international markets, are likely to become more common and attractive, given the success of the GoK Eurobond program. The uptake of the Eurobond signaled that there is a large appetite for investment returns from the country, and investors are willing to take the risk when the investment vehicles or instruments are properly structured, and familiar to international investors. As such, capital raising for such projects in the international markets is expected to be more commonplace in coming years, as the structuring of projects matures to a level where cash flows are ring fenced to cover security holders and provide attractive returns.

## 8.6. GoKs Participation in Funding Kenya's Oil and Gas Sector

GoK's investment in the oil and gas sector has typically been channeled through KPC (for investments in pipelines and storage) and NOCK (for investments in the downstream sub sector). In November 2010, NOCK acquired Block 14T and ventured into upstream exploration; so far exploration activities are still at a preliminary stage. In recent years, these Government owned enterprises, in particular KPC, have increasingly procured financing and made investments without the requirement of GoK guarantees, with KPC primarily funding the new US$ 490m Mombasa to Nairobi products pipeline (Line 5) through bank lending.

Internationally, Governments are rarely the primary upstream investors especially during the frontier exploration stage at which Kenya is in. Whereas investments in pipelines, storage and downstream oil marketing can have relatively predictable returns, upstream exploration is a significantly higher risk undertaking. Therefore Governments usually focus on creating enabling environments for private sector 'risk capital' to invest in early exploration activities. Tools like PSCs and fiscal structures can be designed to both encourage private investment in exploration as well as ensure that the Government and host country share in any successes.

With regard to infrastructure like pipelines and storage facilities, Government participation in development will be key. As discussed earlier, intergovernmental agreements and rights of way procurement will all be required before construction of the crude oil pipeline can commence. For storage, a coordinated plan encompassing construction and siting, as well strategic stock buildup will be required. Naturally GoK (and by extension the Government of Uganda in the case of the crude oil pipeline) are best placed to manage these processes. However given GoK's infrastructure development commitments, and the need to balance provision of social services and infrastructure development within constrained resources, it is unlikely GoK will be able to fund the entire required infrastructure through public funds.

We envision GoK adopting a Public Private Partnership (PPP) approach to the sector's infrastructure development, where the Government creates the requisite investment climate (via legal frameworks, intergovernmental agreements, procuring rights of way, developing a storage development blueprint, provision of sovereign guarantees and letters of comfort, etc.), provides seed capital where necessary, and then invites local and international private sector investors to contribute capital and technical expertise towards specific projects (this structure is described in further detail within this section). In structuring PPPs for mega infrastructure projects, GoK may also choose to incorporate other regional Governments as nominal shareholders, as has been considered for the proposed Uganda refinery where Kenya and Rwanda have taken up nominal shareholding as part of their contribution to the Northern Corridor Integration Projects.

For the crude oil export pipeline, a PPP structure would work well due to the predictability of cash flows and the high capital investment required. Further, in order to raise the capital to develop oil production and commercialise reserves, upstream players will need to have a route to market; it is likely therefore that a 'final investment decision' on developing oil production in Turkana will take place after feasibility and financing arrangements for the crude oil export pipeline have been concluded. As a result of this interconnectivity between upstream field development and the export pipeline project, upstream players with commercially viable finds would be eager to invest capital in the pipeline, in order to support their investments in oil production.

For storage infrastructure, once a policy directing strategic stock buildup and storage facility construction is in place, PPPs can be used to channel private sector capital into these infrastructure projects. With regard to strategic stock, whether Government or OMC's hold the stock, GoK will need to implement a policy that ensures holding costs (interest, insurance and operational costs) are met. Ultimately the end consumer will pay for strategic stocks and the additional storage infrastructure required, and as long as an efficient and transparent mechanism to recoup these costs adequately exists, then PPPs can be structured to deliver the required infrastructure.

While Government owned enterprises like KPC and NOCK can participate in investing in the sector's infrastructure development (including by partnering with other local and international firms), GoK's overarching role in the financing of infrastructure should be to create and implement the necessary legal and fiscal frameworks to attract private capital via PPP-type arrangements. By combining a PPP approach with independent and robust regulatory oversight, GoK can ensure that the required infrastructure is developed in a timely manner, and that fair business practices are adhered to during operations.

## 8.7. Principal Sources of Oil and Gas Funding

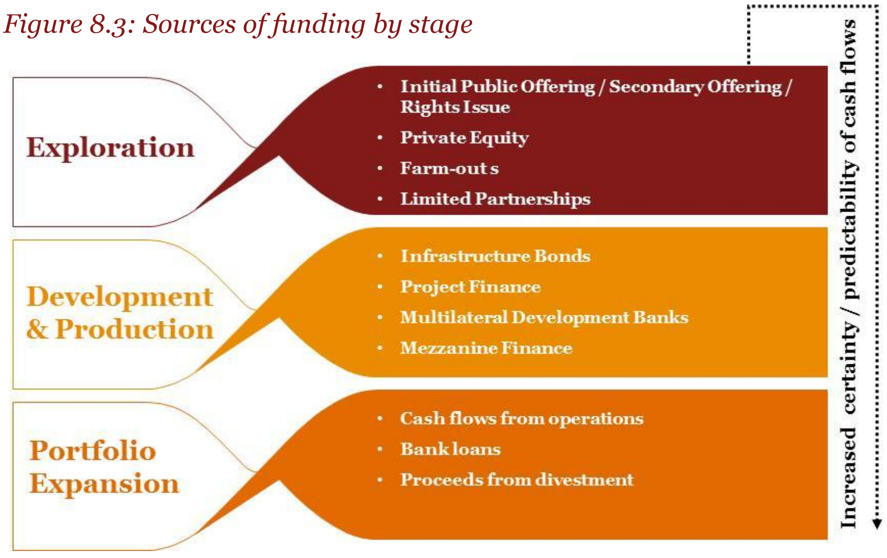
As oil and gas companies transition from exploration to production, positive cash flows from operations become more certain as the projects near and attain commercialisation and expansion. The highest risk segment in the value chain lies within the exploration phase, where the future positive cash flow position for the project is largely uncertain. As such, bank-led financing is typically not readily available for exploration and therefore non-bank i.e. equity sources are usually utilised.

During the development and production phase, companies have greater access to capital markets funding instruments such as listed infrastructure bonds. 'Project Finance' based structures are commonly adopted funding structures for infrastructure development, where finance raising initiatives through ring fenced structures prove to be more successful and are therefore commonly adopted by Governments, and in particular where there is private sector involvement (we will explore this further in this section).

### 1. Exploration

*Initial Public Offerings, Secondary Offerings, Rights Issues* – Exploration companies without income often look to equity markets to fund ongoing exploration. An initial public offering (IPO) of the company's securities to the public is a commonly used mechanism of raising funding. Thereafter, the company can issue further equity through secondary offerings of existing equity or additional shares and/or rights issues. The oil and gas sector is unique, as the value of these companies is essentially supported by reserves and resources in the ground and the technology required to access them. Historically, the New York Stock Exchange (NYSE), London Stock Exchange (LSE) and Toronto Stock Exchange (TMX) have been the dominant capital raising centres for the oil and gas sector. Given the US dollar has traditionally been the reference currency for the sector, a number of non-US major players have typically maintained a secondary listing on the NYSE e.g. British Gas and ENI.

*Figure 8.3: Sources of funding by stage*




*Source: PwC Consortium Analysis*

*Private Equity* –Private equity (PE) firms with lower demand for returns during the initial investment period offer an attractive source of capital for exploration. However, PE firms usually demand a significant upside, and would look to exit the investment at a significantly higher multiple of initial investment once the level of resources have been determined and are ready for commercialization, at which point the PE firms could exit with significant profitability. PEs are generally risk averse and would expect a higher return in the longer term. Global PE backed oil and gas mergers and acquisitions for 2014 Q1 totaled US$ 40.7b across 192 transactions, compared to the 106 transactions during the same period in 2013, valued at US$20.6b *(Source: PLS Inc and Derrick Petroleum Services quarterly reports).*

*Farm-outs* - A commonly adopted finance raising mechanism for oil and gas exploration is the use of "farm–out" transactions. This involves the sale of an oil and gas interest in a block or concession – either partially or entirely to a third party. This presents an optimal solution to retain ownership in exploration while reducing risk exposure and at the same time raising additional capital for exploration and operational activities i.e. operating exploration blocks, financing costs, and testing for the portion of the block retained.

*Limited Liability Partnerships* - Given the multinational nature of major oil and gas exploration companies, they may partner with each other to set up limited liability companies or partnerships for higher risk exploration, for example in developing countries where there may be political vulnerabilities or where there have previously been no proven resources or reserves.

### 2. Development and Production

*Farm-downs* – Farm downs are a common finance raising mechanism for oil and gas exploration companies that are ready to move into the development/production phase of upstream activities. This is similar to a farm-out transaction where a sale of an oil and/or gas interest in a block is sold to a third party. In this scenario, however, the farmer and farmee may both be involved in development and production.

*Infrastructure bonds* – Infrastructure bonds are developed to offer a financing solution for major infrastructure development as an alternative to bank lending. These are generally more attractive as they have longer maturities and fewer covenants and security requirements than bank loans. They are also usually exchange traded, offering liquidity to bond holders.

*Project Finance* – Ring fenced finance raising structures are more commonly adopted for mid and downstream development. The future cash flows of the project essentially serve as collateral for extension of loans, and the structures adopted ensure payments towards debt service before distributions to project sponsors. These structures generally consider a debt to equity ratio of 70:30, whereby debt can be raised from commercial banks, development finance institutions (DFIs), concessional lending or a combination. In order to maximise on project returns, alternative equity structures such as mezzanine finance may also considered.

### 3. Portfolio Expansion

*Cash flows from operations* – Oil and gas companies generally consider expanding their portfolio once they have secure cash flows from development and production of oil and gas. Financing such activities can be done through operating cash flows. Where geographical expansion is considered – for example, tapping into markets with new discoveries, companies can either opt for internal cash flows or consider financing options available for exploration as discussed above, or the securitization of existing surplus cash flows to procure debt that can be deployed on expansion activities.

*Bank Loans* – For short to medium term financing, commercial lending is usually utilised. Long tenures above seven years are typically not available from commercial banks without the requirement to refinance the facilities in order to allow the banks to comply with risk based supervision requirements as guided by Basel 3. For major expansion projects, there is competitive bank funding available from DFIs or concessional lending, which usually has the advantage of longer tenures without the need for refinancing. However, DFI funding typically requires compliance with a number of developmental, environmental and social factors in addition to regular loan covenants that are not usually demanded by commercial banks

## 8.8. Available Financing Structures

Drawing from the oil commercialisation and gas monetisation options identified earlier, we present in this section various financing structures available in this market to develop the recommended options, and thereafter an assessment on the optimal structure that will meet both the public sector and private sector objectives. Broadly, these objectives are as follows:

1. **Government Objectives:**

    a. To deliver projects that offer the highest value for the economy and generate social and environmental benefits.
    b. Minimise on budget constraints. Given Kenya was recently red flagged for its debt to GDP ratio by the IMF, GoK would want to minimise on contingent liabilities, and avoid requirements for seeking additional debt.
    c. Maximising on public sector capital investment. If the GoK provides financing towards projects that are deemed ‘financial viable’, then it should be possible for Government capital to be returned and reinvested in other mega infrastructure projects.

**2. Private Sector Appetite and Capability**

The underlying objective for investing in (infrastructure) projects is maximising returns to the private sector. The private sector would typically have a high appetite for risk if adequate Government support is extended and the business environment is conducive and investor friendly. Upstream players would want to be involved in the development of the infrastructure that will transport any potential oil reserve. This reduces the likelihood of a number of risks to them such as time delays, cost over runs and poor quality construction of pipelines that would result in higher pipeline losses and maintenance costs.

Oil and gas infrastructure is highly capital intensive i.e. crude pipeline; refinery; products pipeline; storage facilities; power plants; and gas pipelines. This Study therefore assesses financing options that are applicable to all assets and the likely associated development/financing risks.

When assessing optimal financing structures for the commercialization and monetization options, it is important to consider which activities are categorized as 'Public Infrastructure'. If for instance an option is considered public infrastructure, this would automatically fall within the mandate of the Government under a public function and cannot be executed by the private sector without Government's participation. The only 2 financing structures that would be applicable would be either a pure public structure or a public private partnership.

## 8.8.1. Funding Structure 1: Pure Public

This structure involves the development, ownership, financing and operation of any infrastructure by the public sector. Given the nature of pure public execution of any project, the Government either directly or through an implementing and/or contracting authority such as a national parastatal would have a financing responsibility, and will therefore need to raise the finance on the contracting authority's balance sheet to fund the development of the infrastructure. It is possible under such structures for the Government to obtain commercial, DFI or concessional funding.

This method does however consider elements of outsourcing or third-party contracts such as turnkey contracts whereby the Government body contracts a third party to design/build the infrastructure in accordance with specified performance standards for a fixed price. This generally implies all project risks will have to be undertaken by the Government except under the turnkey structure where construction risk will rest with the private partner.

**It is unlikely that a ring fenced type structure would be adopted for development of such infrastructure via this financing option, unless the contracting authority creates a special purpose vehicle for delivery of a project.**

### 8.8.1.1. Oil commercialization and gas monetization projects

The key projects identified as routes to oil commercialization and gas monetization are outlined below:

- Crude Pipeline
- Products Pipeline
- Refinery
- Storage Facilities
- LNG import projects
- Gas-fired power generation
- Gas products export projects
- Gas use in industry
- Gas Pipelines

As discussed earlier, the projects identified in this Study may be limited to specific funding structures underpinned by the country's regulatory framework.

### 8.8.1.2. Funding

The financing obligation under this structure will fall with GoK. Based on the costing of the various oil and gas options identified, it is unlikely Government parastatals would have the financial muscle to support the upfront capital investment required without additional funding from the National Treasury. This will ultimately increase the country's debt should the National Treasury be forced to seek external financing in order to execute these investments.

For example, just by considering the cost of the crude pipeline i.e. c. US$ 3.5b, the country's net debt to GDP ratio based on 2013 estimates would increase from 38.7% to c.45%, which is a significant increase when considering the number of mega projects the GoK intends to oversee through to 2030 in addition to the crude pipeline.

### 8.8.1.3. Contingent Liability to GoK

GoK (or its implementing agency) would have to contract a private party to undertake the engineering, procurement and construction works of any asset identified for development of the sector. It is unlikely any company would do so without an extension of a Sovereign Guarantee by GoK which poses a contingent liability to the Kenyan Government. It would be prudent for GoK to limit the amount it exposes itself to a contingent liability emanating from Sovereign Guarantees. Arguably, the GoK has not entered into a situation where there has been a need to call on a Sovereign Guarantee. However with the increasing debt the country is taking on to finance major infrastructure development as well as the funding requirements of the new constitutional dispensation, GoK risks having to make payments as a result of an event of default by a Government entity, or enjoying less favourable terms or access to credit on the international markets due to an event of sovereign default.

### 8.8.1.4. Affordability

It is important to determine the level of affordability to the major stakeholders of the identified projects. This is most critical in the case of public infrastructure which provides a public service.

*1. Affordability to the Government of Kenya* – GoK's existing funding gap for infrastructure development and current debt levels signals that the projects identified under this Study are not affordable to the Government. Despite Government parastatals being the vehicle through which GoK implements major projects, their capital intensive nature will be too heavy a burden for such authorities to carry on their balance sheet, given current resources.

*2. Affordability to the end user* – Affordability to the public would be determined based on what the ultimate end user charge is. Generally under public financing structures, the likelihood of delays and cost over runs are more frequent with delayed disbursements and general lack of independent oversight, and given utility companies generally adopt a revenue required tariff approach, these additional costs would be transferred to the end user through a higher tariff and could render such a structure unaffordable.

### 8.8.1.5. Risks

As the Government would take up responsibility for the development, ownership, financing and operation of any mega infrastructure development under this identified financing structure, they will naturally be the single party that will absorb all the project associated risks. There is therefore no identifiable value for money that can be extracted from this structure in terms of quantifying a transfer of risks to another stakeholder. However based on the construction/turnkey contracts being awarded to the private sector, there will be a minimal quantifiable transfer of construction risk absorbed by the private sector. The Government however will share a large portion of the risks with any private party.

## 8.8.2. Funding Structure 2 – Private Sector development

This structure envisions the development of oil and/or gas infrastructure by the private sector without any Government intervention. The private sector initiates and carries out the finance, building, operations and maintenance of the infrastructure entirely on its own.

Storage facilities are the most probable candidate for private sector development, and a number of storage facilities in Kenya have been developed and are wholly owned by private sector players such as OMCs. However, some of these facilities have had to depend on public infrastructure, with KPC offloading at these facilities. In the case of pipelines, power plants, and transmission infrastructure, pure private sector development may face certain hurdles as there will likely be some level of dependence on public infrastructure or offering of a public service, which would also require regulation. It is likely that those options/pieces of infrastructure would be financed through PPP structures or done through public if the envisaged returns are not attractive enough for private sector participation.

### *8.8.2.1. Funding*

Typically the private sector would raise debt from both local and international commercial banks and DFIs in addition to equity raising through an IPO, a secondary offering or a rights issue, and investment by private equity or other strategic / financial investors. Alternatively the private sector would utilize internal cash flow to fund the development of storage facilities.

### *8.8.2.2. Contingent Liability to GoK*

The Government may engage the private sector to indirectly participate in promoting infrastructure investment. For instance in order to attract the use of infrastructure developed by the Government, GoK may provide investment incentives within close proximity to the asset to attract investors to set up business activities. In such instances, GoK would have to consider providing a form of guarantee to ensure secured revenues to such investors in addition to providing tax allowances.

### *8.8.2.3. Affordability*

*1. Affordability to the Government of Kenya* – Typically the Government will not incur a financial burden under such a structure. However, where the end user tariff is considerably high given the high return requirement by the private sector, GoK may consider regulating the tariff and as such incur expenditure to provide a regulatory body that will oversee this regulation.

*2. Affordability to the end user* – The cost of developing infrastructure such as storage facilities or increase in strategic stock requirement by the private sector will ultimately be passed onto the end user through the pump price. Generally 100% reliance on private sector development can result in considerably higher charges as the expected return to the OMCs will need to reflect the risk being undertaken through pure private funding i.e. all risks will be absorbed by the OMCs. Therefore this may present a situation where the prices are unaffordable to all users.

### 8.8.2.4. Meeting the Objectives

The table below evaluates the extent to which the Government's objectives and private sector capability and appetite may be met through financing of oil and gas monetization options through a pure private structure:

*Table 8.4: Meeting the objectives (Private structure)*

| Social, Environmental and Economic Benefits | | Maximising on Government Capital Investment | |
|---|---|---|---|
| This will generate additional jobs for the public sector through increasing capacity within parastatals for successful delivery of the project. | ✗ | Government capital will not be required and can therefore be reinvested into other mega infrastructure projects. | ✓ |
| Cost efficiencies and adequate management of risks that will reduce environmental hazards. | ✓ | | |
| **Impact on Government Budget** | | **Private Sectors Appetite** | |
| The Government will not be required to allocate any budget to constructing storage facilities as the private sector will bear the entire funding required. | ✓ | Meets the objectives of the downstream Oil Marketing Companies. | ✓ |

*Source: PwC Consortium Analysis*

## 8.8.3. Funding Structure 3: Public Private Partnership Option ("PPP")

This structure sees the involvement of the private sector in the development of key infrastructure. The PPP Act (2013) states:

*'A Contracting Authority that intends to finance, operate, equip or maintain an infrastructure facility or provide a service may enter in to a project agreement with any qualified private party for the financing, construction, operation, equipping, or maintenance of the infrastructure or development facility or provision of the service of the Government in accordance with the provisions of the Act'.*

This structure requires the setup of a Project Company or a Special Purpose Vehicle (SPV) for the purposes of undertaking the specific project. This allows for a ring fenced project finance opportunity in which the project cash flows will serve as collateral for debt.

There are a number of partnership arrangements that fall under the umbrella of a PPP as per the table below:

*Table 8.5: PPP arrangements*

| | |
|---|---|
| Design – Build (DB)<br>Build - Transfer (BT)<br>Build – Transfer – Operate (BTO)<br>Design – Build – Operate (DBO)<br>Build – Operate – Transfer (BOT)<br>Build – Own – Operate – Transfer (BOOT) | The private sector designs, builds and transfers the asset to the Government. There may also be a component of operating the asset then transferring to the Government. |
| Design – Build – Finance – Operate (DBFO)<br>Design – Build – Finance – Maintain (DBFM)<br>Build – Own – Operate (BOO)<br>Build – Develop – Operate (BDO)<br>Design – Construct – Manage – Finance (DCMF) | The private sector designs, builds, finances, owns, operates and maintains the asset with no obligation to transfer to the Government. |

*Source: PwC Consortium Analysis*

## 8.8.3.1. Oil commercialization and gas monetization projects

A PPP structure may be applicable to the following oil commercialisation and gas monetisation options / infrastructure:

- Crude Pipeline
- Products Pipeline
- Refinery
- Storage Facilities
- LNG import projects
- Gas-fired power generation
- Gas products export projects
- Gas use in industry
- Gas Pipelines

## 8.8.3.2. Funding

PPPs generally seek financing from various sources. The level of Debt to Equity typically depends on the acceptable gearing by debt providers and subject to negotiations with financiers (projects within the Kenyan market have seen a debt to total capital ratio ranging between 70% to 80%).

### 8.8.3.2.1. Equity

The project sponsors in a PPP will typically be the investors in the project company. Additional equity is sought from local investors, local Government (this would be optional and only a minimal stake would be allowed under the PPP Act to be taken up), institutional investors, bilateral and multilateral organizations.

Equity contributions can be pledged in the following forms:

- Ordinary Share Capital
- Shareholder loans
- Bank Funded Equity Bridge Loan ("EBL") – this structure delays the timing of equity contributions by seeking funding for equity outside the project company
- Redeemable Preference Shares

Equity returns will be placed at the lowest priority once the project has complied with its debt service in any given period. As such, these projects contain a higher magnitude of risk to investors and therefore demand more favourable returns. It is for this reason that private sector participation is key, as they have a high appetite for risk given their return requirements are higher than the Government's.

### *8.8.3.2.2. Debt*

#### *Development Finance Institutions*

These are Multilateral Agencies established by intergovernmental agreements and are independent of any single member country's interest. DFIs have also been established by individual countries to target funding for both local and overseas projects. The development nature of such financial institutional allows for direct lending, political insurance, and potentially providing equity into a project. The ultimate objective is to promote international and regional economic co-operation and development.

DFIs have played an important role in infrastructure development in Kenya. Institutions such as the African Development Bank, International Finance Corporation ("IFC"), PTA Bank, Deutsche Investitions- und Entwicklungsgesellschaft or / German Investment and Development Corporation ("DEG") and Overseas Private Investment Corporation ("OPIC") amongst others have participated in extending lending to infrastructure development projects in Kenya.

Debt pricing would be competitive with commercial banks, but facilities have the advantage of longer tenure and favourable moratoriums before repayments become due. DFIs typically syndicate with each other to provide more financial muscle to a single project as well as share and diversify risk.

The constraint with DFI sources of financing are the lengthy procedures and restrictions / requirements projects must adhere to in order to qualify for such funding. Such financing however may benefit from additional market instruments such as partial risk guarantees.

#### *Commercial Lending*

Commercial lending by banks has become more prominent in infrastructure financing in Kenya. A number of international banks have a presence in Kenya while others continue to open representative offices to target big ticket deals in the country. In particular the appetite for lending into ring fenced energy development initiatives has grown. The Kenyan market has also proven to offer more secure project structures with heightened commitment from project sponsors and adequate Government support.

Commercial loans typically require refinancing to achieve the longer tenors that are typically offered by DFIs. Alternatively, they can syndicate with DFIs in order to extend the lending horizon. Commercial banks will usually try and syndicate with other banks to spread risk and reduce individual exposure. The advantage with commercial debt is the flexibility to renegotiate loans, as well as relatively quicker decisions for project funding compared to DFIs, with less (if none at all) compliance requirements around environmental and social considerations.

#### *Concessional Lending*

Concessional loans offer substantially more generous terms than commercial banks and DFIs, with much lower pricing, longer grace periods, and tenures that could range beyond 40 years.

The GoK has been afforded a number of these facilities from the World Bank through the International Development Agency ("IDA"), as well as other multilateral lenders such as the Japan Bank for International Cooperation ("JBIC"). Access to concessional type funding generally makes projects more attractive as debt repayments are pushed far out and pricing on debt is more affordable. Such funding is typical where projects are procured directly by Government and when they are less attractive for private sector investment.

#### *Export Credit Agencies ("ECAs")*

The requirement for ECA financing is becoming critical to project bankability in Kenya. A number of countries have established such agencies to support their exporting industry, providing an insurance cover to exporting companies against defaults before and after delivery of the equipment.

Commercial banks can also benefit from credit guarantees for loans that are specifically required for the exported materials. Kenya generally imports infrastructure materials from US, China, Japan and India amongst others, and as such the requirement for ECAs speaks more to the success of projects.

### *8.8.3.3. Contingent Liability to GoK*

The PPP Act (2013) does not specifically state any potential identification of a contingent liability to the GoK under such project structures. However, this is indirectly measured through an adequate risk matrix analysis that needs to be carried out through project feasibility stages in order to identify how risks will be allocated between the Government and the private sector. Project feasibility studies need to demonstrate the quantifiable value for money to the Government through optimal risk transfer to the private sector.

The Private Sector Party will seek a form of guarantee to any PPP project to ensure a 'reimbursement' of funds should the Government default on any contractual payments the Government will be required to make to the private partner. This is a critical instrument that will determine the bankability of such projects as debt financiers will be keen to ensure the projects revenues are guaranteed during any default period to ensure the project will meet its debt service obligations.

The Kenyan market has recently seen the issuance of Partial Risk Guarantees, in particular to IPPs in the electricity sub-sector specifically for the development of geothermal power generation. This is usually provided by a multilateral institution but requires the local contracting authorities to take out a letter of credit which when called upon will be financed by the partial risk guarantee. This is ultimately supported by the GoK who has a separate agreement with such institutions. The Government will therefore have a financial commitment to support such a guarantee and therefore this poses a contingent liability.

GoK has historically issued sovereign guarantees to secure the bankability of such projects, but has recently become averse to doing so. This has subsequently been replaced with the issuance of a GoK support letter that commits the Government to supporting the project from the perspective of ensuring the smooth execution of the project and the contracting authority meets its obligations under any contractual agreements. The letter doesn't any financial guarantee for payments to the private sector.

It is critical to note, projects identified later as candidates for this structure will require a form of guarantee to secure the bankability of these projects and thus posing a potential contingent liability to GoK.

### *8.8.3.4. Affordability*

*1. Affordability to the Government of Kenya* – Payments to the private sector partner under a PPP can either be in the form of a usage payment, availability payment or a performance payment. In the energy sector a usage payment will be adopted where an aggregated revenue required tariff mechanism can be enforced for the demand uptake.

For the purchase of electricity, KPLC is the single offtaker and responsible for power purchase payments to power producers. This is however captured in the retail tariff to end users.

The wholesale prices for petroleum products include the pipeline tariff determined by KPC and regulated by ERC. This is ultimately reflected in the retail price and passed to end users. The crude pipeline will likely adopt a utility revenue required tariff mechanism which will also be passed to the end user. Under such a financing structure and considering the tariff mechanism for the various infrastructure, the Government will have minimal, if any financial obligation, and therefore this will be considered affordable to the Government.

*2. Affordability to the Private Sector* – The payments made to the private partner under the identified tariff mechanisms will have to ensure the private partner is able to recover any costs associated with the development of any such infrastructure, in addition to achieving a desired return for such a structure to be attractive to the private partner.

*3. Affordability to the end user* – Utility tariffs are regulated by the ERC in Kenya to ensure they are considered affordable to end users.

### *8.8.3.5. Risks*

PPPs generally reflect a robust project structure that allows for adequate risk transfer amongst various stakeholders associated with the development of any given project. There are a number of risks that can entirely be avoided; however others will need to be absorbed by an appropriate party to this structure.

Key to lenders determining the bankability of a project is an optimal risk allocation matrix.

*Table 8.6: PPP risk matrix*

| Risk | Mitigation | Risk Allocation |
|---|---|---|
| 1. Construction Risk:<br>• Technical Specifications Risk<br>• Completion Risk<br>• Cost over-run Risk<br>• Design Risk | • Independent Quality Control<br>• Project documentation (penalty deductions)<br>• Fixed Price contracts for supply of materials and provision for contingencies<br>• Independent Engineers | **Private Sector** |
| 2. Demand / Offtake Risk<br>• Market for the Product<br>• Credit Risk on Offtaker | • Take or Pay<br>• Government Support | **Shared** |
| 3. Price Risk | • Hedging (forward fixed pricing) | **Private Sector** |
| 4. Environmental Risk | • Environmental and Social Impact Assessments<br>• Monitoring environmental impact and remediation works | **Shared** |
| 5. Economic and Policy Risk:<br>• Political Risks<br>• Regulatory Risks<br>• Tax Rate Change Risk<br>• Change in Law | • Sovereign and partial risk guarantee<br>• Special compensation for discriminatory unforeseeable conduct.<br>• Termination and compensation for expropriating actions | **Shared** |
| 6. Operating and Maintenance Risk | • O&M Agreement<br>• Penalty Deductions | **Private Sector** |
| 7. Financing Risk:<br>• Cost of debt<br>• Exchange rate Risk<br>• Loan interest rate Risk | • Partial Credit Guarantee (ECA)<br>• Hedging<br>• Fixed rate loans | **Private Sector** |

*Source: PwC Consortium Analysis*

### 8.8.3.6. Meeting the Objectives

The table below evaluates the extent to which the Government's objectives and private sector capability and appetite may be met through financing of oil and gas monetization options through a public private partnership structure:

*Table 8.7: Meeting the objectives (PPP Structure)*

| **Social, Environmental and Economic Benefits** | | **Impact on Government Budget** | |
|---|---|---|---|
| Government can support private funding of Nationally significant infrastructure projects either through filling a funding gap or assisting with enhancing financial viability through GoK support. | ✓ | Dependent on the PPP structure adopted, the private sector may be required to source funding. Alternatively, the payment mechanism identified i.e. user charge or availability payment, the Government would have to allocate budget allowance for an availability payment. The likely payment mechanism for the assets would be an end user charge that would be identified through a tariff. | ✓ |
| This will generate additional jobs through increasing capacity within private companies to develop such projects and a local content Policy. | ✓ | | |
| Cost efficiencies and adequate management of risks that will reduce environmental hazards. | ✓ | | |
| **Maximising on Government Capital Investment** | | **Private Sectors Appetite** | |
| If Government contribution has been factored into debt raising, then as project risk reduces following completion of construction then Government debt can be re-financed or sold down to reinvest in other mega projects. | ✓ | Meets the objectives of the upstream oil and gas players. | ✓ |
| Repayment of Government debt is also dependent on credit ranking of the project. | × | Efficiencies and adequate risks allocation with private sector participation. | ✓ |

Comparison between Conventional Public Contracts and PPPs

*Figure 8.4: Comparison between conventional public contracts and PPPs (1)*

A conventional approach to implementing projects relies on internal capacity which may present challenges such as delays in implementation and cost overruns. Introducing a private partner (in particular given the complex nature of the crude pipeline), technical expertise and sufficient capacity will mitigate any losses from further delays or cost overruns. Furthermore payments to the private sector will only commence once the construction phase is complete and the infrastructure is operational.

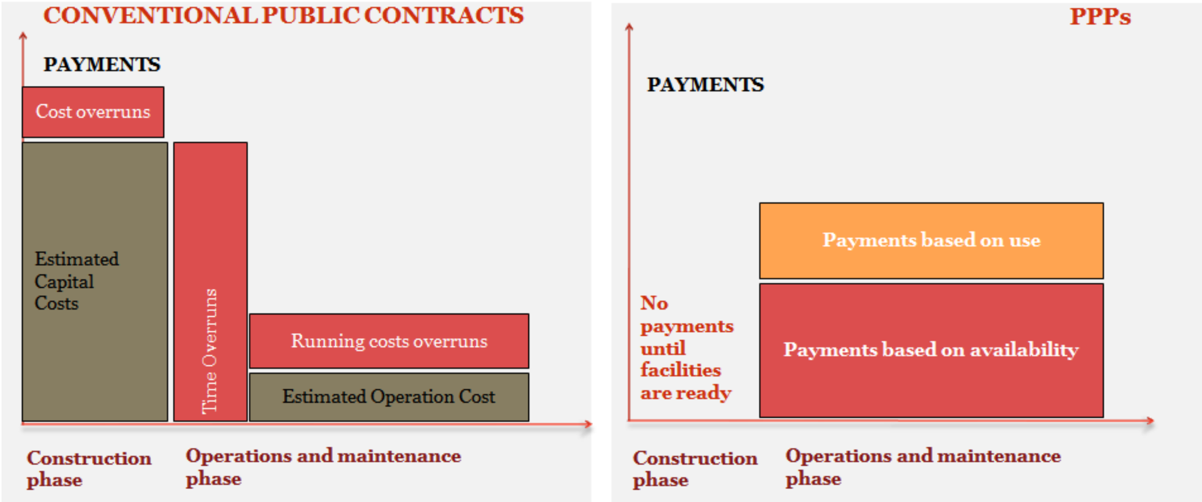
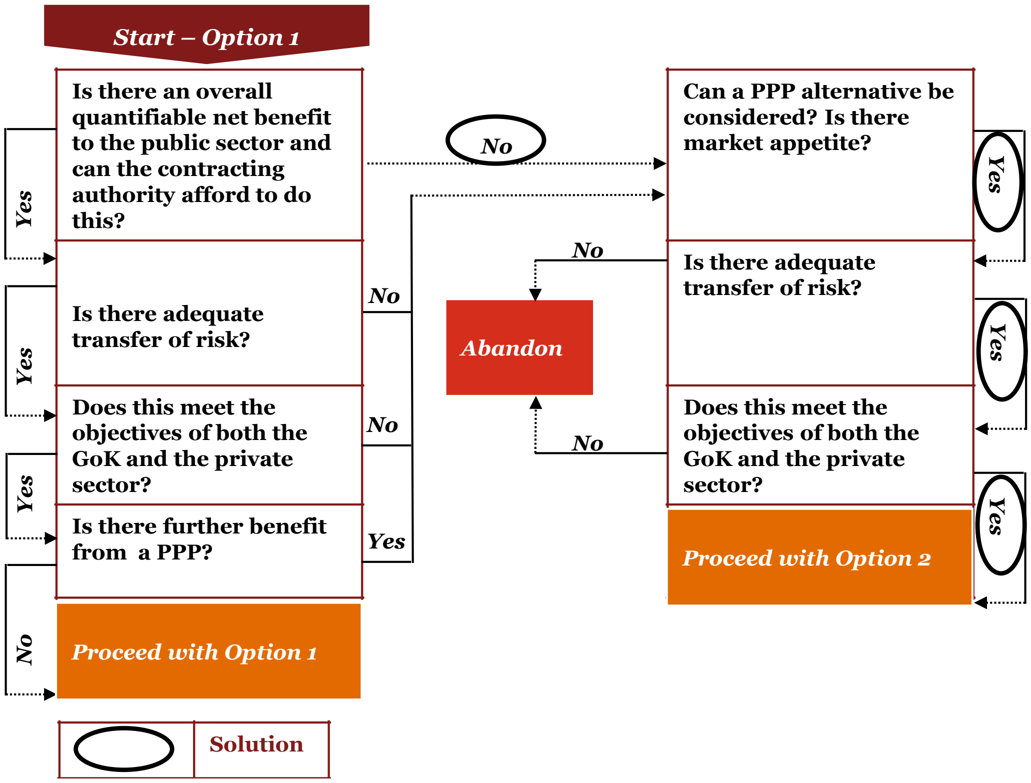


*Figure 8.5 Comparison between conventional public contracts and PPPs (2)*

In order to assist with more informed decision making, a step-by-step decision may be adopted when considering the public procurement structure against a PPP approach to significant capital intensive infrastructure development.




Options 1 = Conventional Public Contract

Option 2 = PPP

# 8.9. Model PPP Structures

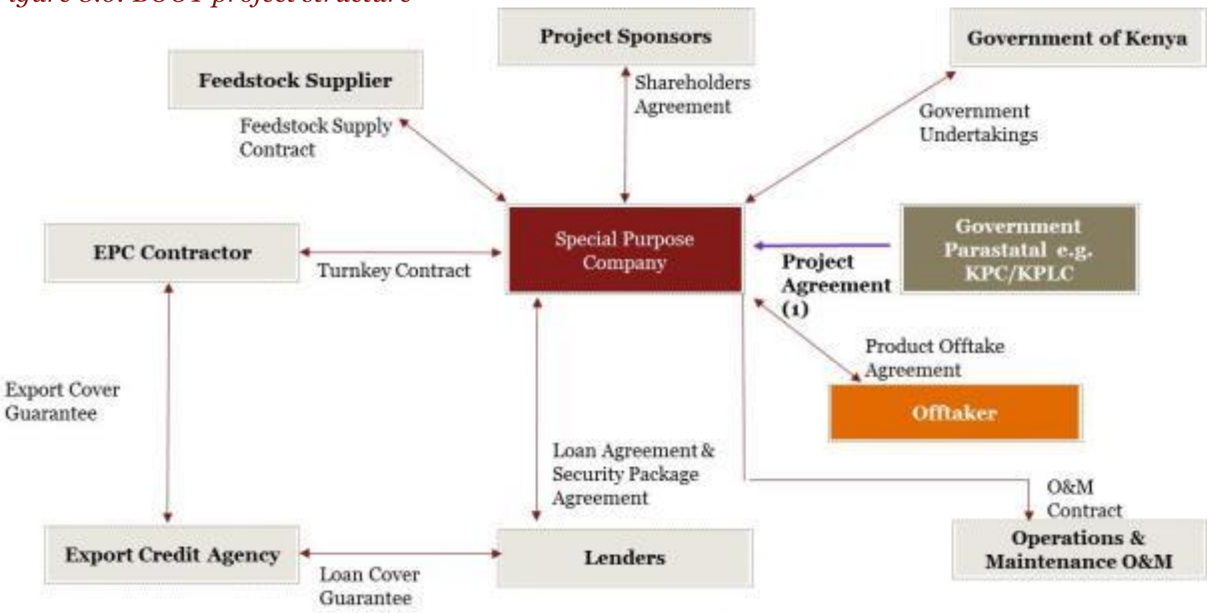
Based on the assessment of various funding structures, the optimal solution to ensuring successful financing of the identified oil and gas options is a ring fenced project finance structure executed within the legal framework of the PPP Act. This section proposes a number of model PPP structures the GoK can consider when executing the development of the identified options.

## 8.9.1.1. Build Own Operate Transfer ("BOOT")

In a BOOT structure, GoK through its parent Ministry or Public Company can enter into a project agreement with a special purpose vehicle that will specifically be set up to execute a single infrastructure development. The project company will then get into third party agreement to carry out construction, operations and maintenance works etc. In order to ensure a tight structure is in place, and mitigate against specific project risks, investors could seek additional comfort through a sovereign guarantee, partial risk guarantees or a Government Letter of Comfort/Support, in the event of project defaults that are not the responsibility of the private party. While this enhances the credibility of the project to financiers, it should be understood that it is not the only option. Risk mitigation guarantees can be provided by a number of other parties including, MIGA, IDA, African Development Bank/African Development Fund and Africa Trade Insurance. Therefore, investors can take it on themselves to secure this protection from the above sources.

Under this structure, the private party will be responsible for the design, construction, financing, operation and maintenance of the infrastructure. The asset will be owned by the private company during the period of the project agreement which typically should not exceed 30 years. Upon expiry of the project agreement, the private party will be required to transfer the asset to the Government or Government authority at an agreed value between the parties to the agreement.

*Figure 8.6: BOOT project structure*



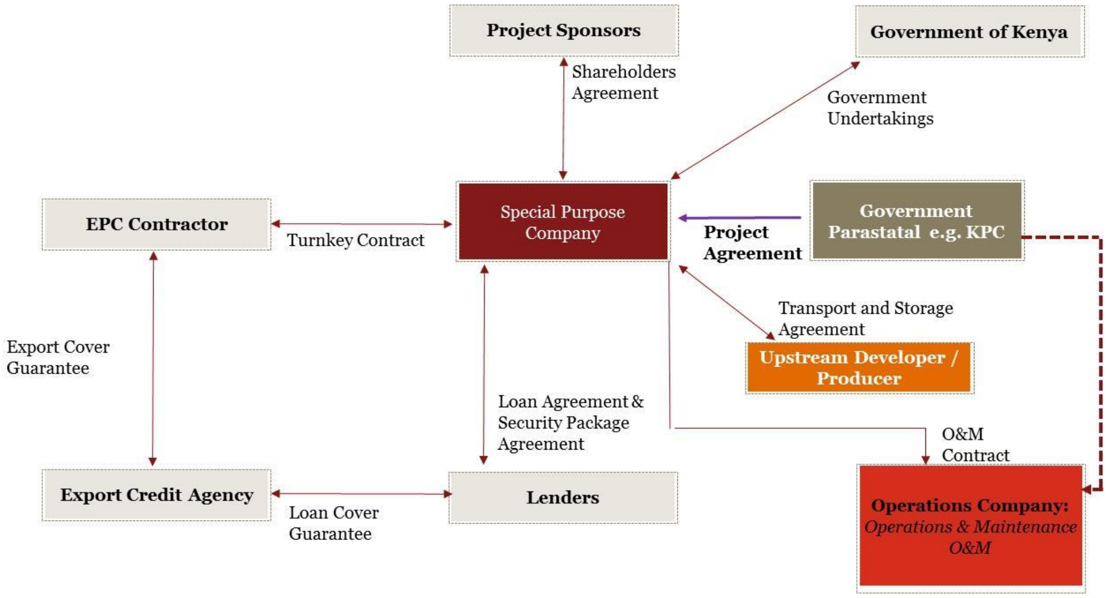

*Source: PwC Consortium Analysis*

(1) Transfer of asset to Government authority on expiry of the PPP Agreement.

### *8.9.1.1.1. Build Own Operate Transfer for Crude Pipeline Option 1*

This structure is a mutation of the BOOT described above and tailored to the crude pipeline alone, where Kenya Pipeline Company plays a more active role in the operations of the crude pipeline. KPC will continue to play the role as the contracting authority with the private sector in addition to being a partial owner in an operating company. Given the specialized technical skill required for the development of the crude pipeline, partial ownership in the operating company will allow for skills transfer to KPC and upon transfer of the asset after the PPP project period to KPC, the company will be more equipped to continue operating the asset.

*Figure 8.7: BOOT project structure for crude pipeline option 1*

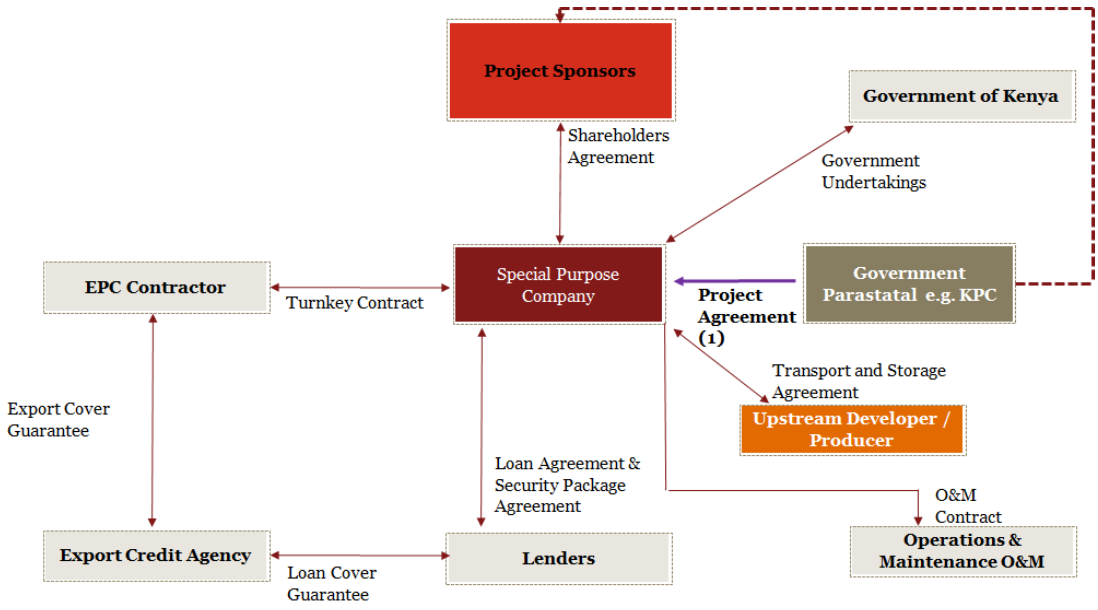



*Source: PwC Consortium Analysis*

### *8.9.1.1.2. Build Own Operate Transfer for Crude Pipeline Option 2*

Alternatively, KPC could participate as a project owner with a non-controlling stake in the SPV. However, this would require a capital commitment from KPC according to its ownership portion which may present a financial strain on the company's balance sheet given the heavy capital cost required for the development of the crude pipeline, and KPC's existing commitments related to product pipeline upgrades and expansions. Further studies would need to be undertaken to determine the financial capability KPC would have to participate in the project company.

*Figure 8.8: BOOT project structure for crude pipeline option 2*




*Source: PwC Consortium Analysis*

## 8.9.1.2. Build Own Operate ("BOO")

This structure is similar to the BOOT, where the private party designs, finances, constructs, operates and maintains the infrastructure for a period of time as agreed upon between the contracting authority and the private partner. This structure will however require the private partner to decommission the asset.

Development of power plants in Kenya are usually undertaken within the framework of a BOO. The challenge arises where upon expiry of the project agreement there is still available resource of energy. In some cases this structure may be justified for the development of power plants, however detailed resource studies would need to be carried out during the feasibility stage to determine the length of time these sources of energy would be available. Such a structure has generally only been applied to geothermal power projects in the Kenyan market.

An example of the development of the oil and gas sector through ring fenced project finance structures include the Chad-Cameroon Pipeline. This project had two separate components – oilfield development and construction of an oil pipeline. The development of the oil pipeline and marine facilities cost approximately US$ 2b and was undertaken as a project finance transaction, where the pipeline system was operated and maintained by two joint venture companies with both the Government of Chad and the Government of Cameroon having a minority stake arrangement in the project[24]. It is important to acknowledge the participation of major oil companies in the Chad-Cameroon pipeline were secured as a result of the participation of multilateral agencies due to the high political and economic risk.

Other examples include the natural gas pipelines in Colombia – TransGas and CentraGas that were both undertaken as Build-Operate-Maintain-Transfer projects[25].

[24] http://web.worldbank.org/archive/website01210/WEB/0__CO-15.HTM
[25] http://ir.nmu.org.ua/bitstream/handle/123456789/131143/4979516be312e5a851351d9a21100089.pdf?sequence=1

## 8.10. Recommendations

### 8.10.1. Findings

- Different projects, dependent on their risk-return profile as well as social importance will attract various forms of funding. The appetite and necessity for funding by either the Government, private sector, or a combination of both will largely be dependent on the risk allocation of these projects as well as value for money.

- It is clear that the role of the private sector (upstream players, oil marketing companies and other private financial and strategic investors) in the development of pipelines, storage facilities and power plants is critical. The Government needs to ensure streamlined development and ownership of key infrastructure in the oil and gas value chains in order to secure the sectors performance through early commercialization and monetization, and to mitigate risks.

- There are still some uncertainties surrounding the legal and regulatory framework for upstream players. GoK should work to tighten the framework within which it intends to develop the industry and ensure first oil and first gas by the desired dates.

- The country is yet to develop the basis for the crude pipeline tariff and gas pricing methodology. There is an immediate need for this analytical basis to be defined.

- That Government has enabled a conducive investment environment for both local and foreign investors. However there are still a number of risks that need to be addressed. To ensure the success of the sector, the Government should undertake a study on the sector specific investment framework to determine whether it is considered an attractive environment and where the gaps lie if any.

- There is minimal capacity within the local economy to sustain mega infrastructure development. This includes local skill, as well as financial capacity of Government authorities and the local banking sector. Foreign participation should be encouraged in order to bridge the skill and financing gap, with a push for local skills transfer.

### 8.10.2. Recommended Actions

- **Bilateral Agreement on Crude Pipeline –** The Government needs to agree on the funding structure that will be adopted for the development of the crude pipeline. Given the bilateral agreement that will need to be drawn up for the development of the pipeline, it is crucial that this process be completed early in order to facilitate the commercialisation of oil by the desired date.

- **Funding the Crude Pipeline -**It is understood a feasibility study is being undertaken by Kenya, Uganda and Rwanda to validate the previous studies that were completed to determine the route the crude pipeline should adopt. We would recommend the three Governments undertake a detailed financial feasibility study to determine the optimal funding structure for the development of the crude pipeline. We note that since this project is the linch pin and critical for the development of the sector, and the cost implications are substantial, the financing should be envisaged and developed via the private sector primarily, with minimal or no public funding.

- **Crude Pipeline Tariff Study** – As per the tariff setting discussion in this section, the country does not currently have in place a tariff for the crude pipeline. The cross border nature of the pipeline may give rise to various complexities in tariff setting. At this stage we are unable to determine these; however it is important for the Kenyan and Ugandan Governments to carry out a tariff study for the crude pipeline. This will be a key determinant as to whether the crude pipeline development will be considered financially viable or not.

- **Gas Pricing / Tariff Study** – GoK needs to carry out a detailed study to determine a gas pricing/tariff methodology for the identified gas monetization options. This should be undertaken as part of developing a Gas Policy for the country.

- **Common Carrier Legislation** – Should the Government consider the optimal funding structure for the pipeline discussed in this section (this would also apply to any potential gas pipeline), there will be a need to streamline and ratify the Draft Energy (Operation of Common User Petroleum Logistics Facilities) Regulations developed in 2011 to the requirements of upstream players in addition to updating the legislation to take into consideration the cross border nature of the pipeline. This will also ensure that transportation of crude from satellite fields plugging into the initial (main) pipeline would have an enabling environment.

- **Guarantees and Government support** – The funding options analysed would require various forms of Government support. For instance, the pure public financing option will require GoK to prepare itself to provide sovereign guarantees. PPP structures will generally require a partial risk guarantee or in some cases a sovereign guarantee, and a Government letter of support. GoK will need to start engaging multilateral partners to provide such guarantees for the various development options identified. Without this support from GoK the bankability of such projects may be questionable.

- **Tax structures on projects** – The pace at which Kenya can commercialise oil and monetise gas will be dependent on the funding structures available for projects. A particular consideration the Government needs to pay closer attention to is the tax structures for various project implementation mechanisms; heavy, upfront taxes tend to deter foreign investments. For instance, under a PPP structure the project company has to be a limited liability company registered in Kenya. This attracts significant taxes to the company including compensating tax, particularly on the remittance of dividends paid out of untaxed profits, as well as tax risks arising out of thin capitalization in the event that the project company with predominantly foreign shareholding is largely funded through shareholder loans. The current fiscal regime results in a local branch structure of a foreign entity being a more favourable investment vehicle for foreign investors. Such structures also allow for easier access to offshore financing.

- **Investment framework for the oil and gas sector** – to ensure an investor friendly environment for the oil and gas sector, the Government should set up a working group that includes GoK representatives, upstream players and downstream oil marketing companies to discuss the challenges investors face in the different value chains and the potential improvements the Government could consider in the legal and regulatory framework. In addition, the Government should use this as an opportunity to educate the private sector on the existing framework and the Government's justification for this framework. This working group would allow all parties to build consensus around topical issues.

- **Building the local financial sector** – the Government, alongside the Kenya Bankers Association and other financial intermediaries, should take active steps towards strengthening the local banking and capital markets to enable them have greater participation in the mega infrastructure projects earmarked for implementation in the country, with the aim of retaining capital within the economy but without discouraging foreign investment.

# *Experience in Other Countries*

# 9. Experiences in Other Countries

In this section we consider key learnings from other international oil and gas sectors both upstream and mid/downstream, and the potential implications for Kenya. Given that there is already a downstream oil sector in place in Kenya which has been covered in our work the two main areas of focus have been the upstream sector and the gas sector. We also consider lessons in respect of the environmental and social aspects of the oil and gas industry.

## 9.1. Upstream benchmarking summary

### 9.1.1. Background

In seeking to compare Kenya with other international upstream sectors, it should be remembered that Kenya is still in its infancy as an upstream play and there is much further work and investment to be made by industry players in order to realise the potential. Therefore, in the short term the emphasis should be on developing the optimum environment for further investment in the sector as this is a prerequisite for those potential benefits that might accrue to the local and national communities within Kenya as the sector develops and matures. This is particularly the case in a low/volatile global oil price market environment where international companies are more likely to prioritise their investment funds in those countries offering the best risk/reward prospects.

### 9.1.2. Policy, licensing and legislative framework

The ongoing review of the existing legislative framework in Kenya is a progressive step that should provide stability to investors moving forward. The successful completion of this framework review will enable Kenya to fast track its exploration and production activities by providing certainty to investors. Kenya should also embrace an open competitive process for oil block allocation to ensure process transparency, quality of contracts, and encourage a wider participation.

Based on the experiences of other countries with onshore hydrocarbon reserves, like Trinidad and Tobago, there is a need to ensure harmonisation between petroleum policy and land policy, especially where surface access rights for upstream operations are concerned.

The implementation of policies to secure a nation's future energy needs may face some resistance and could sometimes negatively harm a country's oil and gas sector, as observed in Canada and Israel. Going forward, Kenya will need to strike a balance between securing its own energy demands while engaging with relevant stakeholders to ensure that investments into the industry are not adversely affected.

### 9.1.3. Local participation and capacity development

State company participation should be considered in order to ensure sector knowledge and skills transfer, as well as promote the wider national involvement in upstream operations. Participation of NOCK or any other state owned company in ongoing upstream activities will enable Kenya to build its local capabilities which can further provide an environment where local private companies can increase their stake in exploration activities. Kenya's model PSC requires contractors and sub-contractors to employ Kenyan citizens and provide training to them. A strong legislative framework governing activities in the sector with regard to local content should go hand in hand with building local capacity, although care must be taken not to adversely affect potential upstream investment due to a lack of suitable local capacity.

### 9.1.4. Development of a conducive business environment

Developing a support structure for upstream operations, including infrastructure, political stability and security, efficient dispute resolution procedures and a skilled workforce, will not only facilitate an increased level of inward investment but could also allow Kenya to retain a better share of earnings from her resources than would otherwise be sustainable.

## 9.1.5. Sovereign fund

Kenya should consider establishing a sovereign or savings fund when revenues from oil and gas are realised. The fund's aim(s) could include saving for future generations, stabilising the economy from commodity price swings and/or investment to enhance economic growth. In developing the policy for this fund, GoK should adopt international best practices like the SWF's Generally Accepted Principles and Practices ( "GAPP", "Santiago Principals").However, care must be taken to manage stakeholder expectations in this regard as the potential economically recoverable hydrocarbons whilst substantial, are relatively modest compared to a number of other nations that have set up similar schemes.

## 9.1.6. Developing human capital

Kenya can benefit from utilising its already established education system and learning institutions by introducing an oil and gas curriculum which can be done through partnerships between NOCK and other state owned institutions within the oil and gas value chain. The curriculum should not only focus on mainstream oil and gas technical capability but should also encompass support services. This will allow for greater employment opportunities for local populations and in the long run this staff component could also support other regional developments and become a source of export revenue for Kenya.

## 9.1.7. Summary of Observations- Learning and implications for Kenya

*Table 9.1: Summary of key upstream learning points*

| Learning Point | Summary of observation | Implications for Kenya |
|---|---|---|
| **Adaptability of a fiscal regime in light of changing acreage dynamics** | Countries provided adaptability in their fiscal regimes and tax incentives to attract investors into more risky exploration acreage | Kenya's energy legislative framework is currently under review led by The Ministry of Energy and Petroleum in consultations with relevant stakeholders. Its finalisation, including revisions to the existing model PSC, should aim to create more certainty for investors and provide a rate of return that ensures that Kenya remains an attractive investment option for international players given the perceived level of risk involved.<br><br>Once this legislation is passed, Kenya could learn from other countries by allowing flexibility in the future to provide fiscal incentives as the exploration acreage environment changes to attract investment into less attractive acreage.<br><br>Malaysia and Trinidad and Tobago have provided incentives to attract further investments as their exploration environment has changed. In the case of Malaysia, a drop in production due to maturing fields led to the introduction of Risk Service Contract fiscal regime alongside the PSC fiscal regime to encourage investors to conduct exploration and production within marginal fields. The regime allows contractors to recover development cost and pays them service fees. Under the fiscal regime contractors also benefit from a reduced tax rate of 25% from 38%. Following the introduction of the alternative fiscal regime Malaysia has been able to attract investments into marginal fields. **GoK must take into consideration that it remains in the early stages of upstream development.** Therefore, investors will require a relatively attractive tax environment in order for Kenya to compete effectively with other nations offering exploration opportunities, as well as a stable political environment. |
| **Fast tracking policy development to provide** | Israel and Ghana have been able to develop their oil and | The ongoing review of the existing legislative framework in Kenya is a progressive step that will provide stability for investors moving forward. Ensuring the process is inclusive and reflective of stakeholder issues will enable Kenya to develop a legislative framework that will attract investments and ensure development of the industry. |

| Learning Point | Summary of observation | Implications for Kenya |
|---|---|---|
| **certainty to investors.** | gas sectors by fast tracking the development of a legislative framework within which investors can operate | Israel and Ghana have made significant discoveries in recent years and they have been at least partially successful in being able to fast track development of their oil and gas sectors by adopting a suitable legislative framework within which investors are currently operating.<br>In Ghana exploration started in 1896 and production started years later but declined. Modern day oil and gas in Ghana was discovered in 2007 and production started in 2010. This was made possible through various regulatory, structural and legal decisions that were made either before the discoveries were firmed-up or shortly thereafter.<br>In Israel, following significant discoveries, the Government appointed the Shenshinki Committee to review the county's fiscal regime in 2010 following which the committee's recommendations were adopted in 2011 under the Petroleum Taxation Law. Israel has been able to fast track investment into its gas industry with production in the Tamar field beginning in 2013 within four years of discovery. However, the country has more recently been undergoing a review of the natural gas policy framework under a different committee that provided guidance on domestic supply requirements and export quotas. The outcome of these deliberations has been to impose onerous restrictions on upstream activity due to the need to find a local market for a large proportion of new gas fields. Some explorers have now put investment plans on hold, pending further changes in the Government's stance. |
| **Building local capabilities through legislation** | Experience from oil producing countries including Ghana and Nigeria show there is need to enact a comprehensive local content legislation to build local capabilities | Kenya's model PSC requires contractors and sub-contractors to employ Kenyan citizens and provide training to them. It also requires contractors and subcontractors to give preference to local goods and services.<br>Currently, market participants such as Tullow are incorporating local content programmes into their activities through procurement, employment and capacity building. In 2013, Tullow ran eight seminars with suppliers in Ghana, Kenya and Uganda to build local capability within local businesses. At the end of the year, the company had spent US$ 48 million in local supplier contracts and employed 77 (although a drop from 92 in 2011) Kenyan nationals. Such initiatives under a strong legislative framework will improve the country's local content inclusion in the sector and provide a strong basis for future investments and developments.<br>Kenya will greatly benefit from developing a more comprehensive local content legislative framework in its ongoing legislative reviews. Such legislation should be fast tracked as it will be important in setting and managing expectations for the sector, as well as directing Government and private investment into initiatives that aim to build local capacity. The aim is to create a workable balance between the need for local involvement and development of skills and the specific skill sets necessary to ensure ongoing investment in the sector. |
| **Building local capabilities through capacity building initiatives** | A strong legislative framework governing activities in the sector with regard to local content should go hand in hand with building local | In the case of Malaysia the Government has delegated responsibility to the national oil company PETRONAS and two other agencies established under the Prime Minister, Malaysian Investment Development Authority and Malaysia Petroleum Resources Corporation to ensure that local content initiatives are designed and implemented. These Government agencies through the Economic Transformation Programme are building capacity of Malaysian business to encourage participation in the oil and gas sector. More recently, under the ETP programme Malaysia is taking several initiatives to transform Malaysia into a hub for oil and field services by building the capacity of local companies and encouraging investments. Some of the initiatives the country has undertaken include encouraging joint ventures between local companies and international companies and incentivising the consolidation of smaller players to form larger domestic companies with stronger technical and financial capabilities. |

| Learning Point | Summary of observation | Implications for Kenya |
|---|---|---|
| | capacity | |
| **Role of state owned enterprises in building local capabilities and transfer of knowledge** | A number of countries, especially in the emerging markets, have benefited from the transfer of knowledge and strengthening of local capabilities through participation of state owned enterprises in the their oil and gas value chains | Kenyan state owned enterprises have long been taking part in midstream and downstream activities through KPC, NOCK and KPRL (50% GoK owned). In the upstream sector, NOCK in 2010 was licensed to undertake exploration activities in Block 14T in the Tertiary Rift Basin.<br>Participation of NOCK or any other state owned company in ongoing upstream activities will better enable Kenya to build its local capabilities which can further provide an environment where local private companies can increase their stake in exploration activities.<br>Malaysia's national oil company, PETRONAS takes part in the entire oil and gas value chain and has been a significant player in building local capabilities in Malaysia.<br>PETRONAS was established in 1974 and has grown to be one of the largest players in oil production in Malaysia. Over the years, PETRONAS anchored its technical capability in the sector by partnering with international players which has enabled the transfer of knowledge. PETRONAS has then in turn established learning institutions and universities providing technical training to local Malays who have then been absorbed into the oil and gas workforce.<br>Kenya can benefit from utilising its already established education system and learning institutions by introducing oil and gas curricula which can be achieved through partnerships with state owned enterprises within the oil and gas value chain.<br>In the medium term such initiatives will build a workforce that can then be absorbed into the oil and gas sector. As the sector matures and the demand for technical skill increases, more public and private owned learning institutions and universities can be involved in order to meet the growing needs of the sector in the medium to long term. Kenya could in time become a hub of oil and gas sector knowledge and services across the East Africa region. |
| **Stimulating demand** | Countries have managed to spur development in their oil and gas sector by implementing policies that stimulate demand for discovered oil and gas | Following the anticipated discovery of natural gas in Kenya, policies would need to be aligned to stimulate domestic use of natural gas. The Kenyan Government already has plans to develop LNG power generation facilities in its medium electricity generation plans. Other gas-intensive industrial projects could be incorporated in such policy to further increase demand for natural gas.<br>These large industries and power plants can be designed as industrial hubs and spur smaller industrial firms, along the lines of (although not necessarily as extensive as) Trinidad's Point Lisa's industrial estate which includes power generation, petrochemicals, steel and other industries. However, this will be contingent on both the scale of gas deposits found in Kenya and the costs of extraction as many of the potential large users would require low cost gas in order to compete internationally (e.g. methanol, fertiliser plants).<br>Israel has also increased its electricity production using natural gas following discoveries, which has formed the basis for increased domestic demand for the resource. Electricity production from natural gas in proportion to total production has increased from 9.2% (when gas first came on-stream) in 2004 to 37.5% by 2010. In 2013 natural gas production began in the Tamar field and the expected production from Leviathan is set to further increase the proportion of electricity generated using natural gas.<br>In the case of Canada, following significant oil discoveries in Western Canada the Federal Government introduced the National Oil Policy in 1961. The policy gave Canadian producers exclusive rights to sell oil in Western Canada by curbing imports. This policy promoted the oil industry in Western Canada by securing a protected share of the domestic market. The policy was widely supported by Canada's oil industry and the Governments of producing provinces in the West. The Federal Government also facilitated the |

| Learning Point | Summary of observation | Implications for Kenya |
|---|---|---|
| | | construction of inter-provincial and international pipelines promoting exports to the US. As demand developed, these protectionist policies were removed and market forces were allowed to prevail. |
| **Securing national future energy demand** | Countries have taken various approaches in securing their future energy needs | Whilst Kenya may benefit from a short-term interventionist approach in order to stimulate growth, it must be careful to manage how this will be implemented and for how long such an approach might be applied.<br>In Canada, concerns over adequacy of reserves in meeting future rising demand resulted in the introduction of a National Energy Programme in 1973 which broadened federal intervention in the energy business by curbing oil and gas export and regulating the prices of these commodities sold to the market outside the provinces of production. These initiatives led to a crisis in federal-provincial relations. As a result oil and gas production remained stagnant during 1973- 1984.<br><br>In 1985, the federal Government of Canada instigated major changes in the policy towards eliminating federal Government's intervention and moving towards a market driven framework. This approach resulted in a sustained increase in exploration and production activities.<br>Since then, there has been no major departure from the market driven approach to federal oil and gas policy in Canada with market forces influencing the oil and gas upstream operations in the country. The upstream activities of the provincially owned companies were turned over to the private sector.<br>In Israel, natural gas policies to secure future domestic demand have recently been reviewed following the discovery of major offshore fields. The inter-ministerial committee appointed by Government to review natural gas policies provided recommendations to introduce export policies that will guarantee a local supply of natural gas for Israel energy needs for a period of 25 years. However, following a long consultation process and political debate, the constraints imposed on the upstream players are such that the level of investment in the sector has decreased significantly. It is likely that Government policy will need to be revisited if major new investments are to be realised.<br>The implementation of policies to secure a nation's future energy needs may face some resistance and could sometimes negatively harm a country's oil and gas sector as observed in Canada and, more recently, Israel.<br>Going forward Kenya will need to strike a balance between securing its own energy demands while engaging relevant stakeholders to ensure that investments into the industry are not adversely affected. Kenya's model PSC requires contractors to supply crude oil for domestic consumption in priority to exports. The finalization of the legislative framework including PSC terms will need to involve relevant stakeholders to test acceptability of the domestic supply obligations in the PSC.<br>It is important to note that one of the reasons why it is thought that Nigeria's PIB has been delayed in its execution as long as it has is due to the apparent challenges the Government faces in taking into account and effectively balancing the needs and desires of all key stakeholders. |
| **Harmonisation of land and petroleum policy** | There is need to ensure harmony between petroleum policy and land policy. | In Trinidad and Tobago exploration companies have sometimes had to pay royalties to private owners who still hold subsurface rights on exploration acreage approved for exploration - this acts as a disincentive to investors. While subsurface rights in Kenya are all vested in Government, surface access needs to be negotiated. Further review of Kenya's land tenures and specifically communal land would be needed to determine potential effects and mitigations with regard to petroleum exploration and production. |

| Learning Point | Summary of observation | Implications for Kenya |
|---|---|---|
| **Political stability as a catalyst to investment** | Countries with political stability have managed to attract investments into their oil and gas sectors | Trinidad and Tobago has managed to sustain investments into the sector despite slightly higher taxes than the average hydrocarbon rich country, which has been supported by a stable political environment. It should be noted that initial investments were made in a more attractive tax regime, but this has been amended over time to provide for a greater take for the Government as oil prices increased.<br>Developing a support structure for upstream operations, including infrastructure, political stability and security, efficient dispute resolution procedures and a skilled workforce, will facilitate an increased level of investment in the sector and could allow Kenya to retain a better share of earnings from her resources than would otherwise be sustainable.<br>Specific taxes on the sector, along the lines of Trinidad's Unemployment Levy and Green Fund, can be implemented to develop the social well-being of the people of Kenya which can further enhance security and promote a politically stable atmosphere. However, it is important that the overall tax burden is set at a level that ensures that investors achieve acceptable returns on their investments. |
| **The allocation of blocks through competitive bidding** | Awarding of exploration blocks through competitive bidding will ensure that Kenya attracts companies with the required expertise and financial capability to conduct exploration and production | Both Ghana and Nigeria have experienced negative effects from discretionary block allocation. Kenya should learn from the experience of these oil rich nations and embrace an open and competitive process for oil block allocation.<br>The companies that succeed in getting licences should be those that have the requisite financial muscle, technical capability and that have committed to a significant local involvement. These firms must be dedicated to the transfer of skills to the local workforce and commit to have senior positions held by locals.<br>All the licences should include achievable target timelines for contractors and must only be renewed upon evidence of significant work done.<br>As is the case in Ghana,the Government – through an upstream regulator – should monitor the activities of all contractors. |
| **Establishment of a Sovereign Wealth Fund** | Countries have established Sovereign Wealth Funds to provide cushioning against future oil and gas price volatility | In the future, as revenues from oil and gas become embedded into the Kenyan economy, a Sovereign Wealth Fund could be established.<br>Sovereign Wealth Funds have been adopted in several oil and gas producing nations and can be used to benefit a country in various ways:<br>• Finance budget deficits from which investments can be made across economic sectors.<br>• Insulate the economy from the effects of commodity pricing cycles and other economic turbulence.<br>• Savings fund for future generations to meet public sector obligations while alleviating any negative sector outcome such as the Dutch disease.<br>Detailed research should inform the policies on how and what the fund will invest in, and when and how withdrawals can be made from the fund. In doing so, Kenya should adhere to the SWF's Generally Accepted Principles and Practices ("GAPP", "Santiago Principals") which fall under the three main categories below and broken down Appendix I. |

| Learning Point | Summary of observation | Implications for Kenya |
|---|---|---|
| | | 1. Legal framework, Objectives and Coordination with Macroeconomic Policies.<br>2. Institutional Framework and Governance Structure.<br>3. Investment and Risk Management Framework.<br><br>Trinidad and Tobago introduced a stabilisation sovereign fund after the economy suffered from the collapse of oil prices in the 1980s. The fund was set up after the recovery of oil prices in the 1990s and was formalised in 2007 as the Heritage and Stabilisation Fund.<br>Nigeria set up the Nigeria Sovereign Investment Authority to manage Nigeria's excess oil revenue above budgeted revenue. The authority was established as an independent agency by an Act of the National Assembly in 2011 with an aim to cushion Nigeria from cyclical oil prices and depletion of its hydrocarbons. The fund is governed under a Heritage and Stabilisation Fund Act which provides policy on the governance and management of the funds including savings, investments and withdrawals.<br>Other countries within the region that have set up stabilisation funds include Algeria which by 2014 held the largest fund in Africa. Algeria's Revenue Regulation fund was set up in 2000 to cushion the economy from price volatility in gas and oil commodities. By 2014, the fund held US$ 77B of total assets.<br>The largest Sovereign Wealth Funds from oil and gas revenues are held by Norway and United Arab Emirates whose funds have been in existence for over 20 years. |

| Country | Fund | Assets - US$ billions | Inception |
|---|---|---|---|
| Norway | Government Pension Fund | 878 | 1990 |
| UAE - Abu Dhabi | Abu Dhabi Investment Authority | 773 | 1976 |
| Algeria | Revenue Regulation Fund | 77 | 2000 |
| Trinidad and Tobago | Heritage and Stabilisation Fund | 6 | 2000 |
| Nigeria | Nigeria Sovereign Investment Authority | 2 | 2011 |
| Ghana | Ghana Petroleum Funds | 0* | 2011 |

* US$ 72 million

*Source: PwC Consortium Analysis & Sovereign Wealth Institute, 2014*

## 9.2. Midstream and downstream benchmarking summary

### 9.2.1. Oil

A cross-section of countries was selected for the mid and downstream oil benchmarking review. These countries have been evaluated in order to understand the key issues and learning points from the highly centralised regulated market of Nigeria through the Malaysian, Indian and Turkish markets to the market driven deregulated market of Canada.

Against this objective we looked for key lessons and implications for Kenya in the key sectors:

### 9.2.1.1. Regulation, Subsidies, State-owned assets and Import Parity Pricing

- In terms of regulation, the roles of policy and implementation should be separated - Canada and Turkey have achieved this successfully via a two-tier Government structure and a separation between the Ministry and a regulatory authority, respectively. On the other hand, Nigeria's centrally controlled sector led to loose oversight and corruption issues.

- Subsidies and cross subsidisation are to be avoided as once implemented are difficult to reverse and costly to Government and the country. In India, Nigeria and Malaysia, attempts at Government reform have been slowed by fear of a popular backlash against rising prices. In addition, subsidies further affect the economy by discouraging private sector commercial investment.

- Development of state owned petroleum assets and the transition to privatised assets is a process which needs to be carefully managed. Turkey privatised its National Oil Company, TUPRAS, through its privatisation authority with some shares being offered to the public and a 51% balance was finally sold to an Oil Company Joint Venture. This sale represented the successful culmination of a well-planned 15 year transformation from state to private ownership.

- Import parity pricing is important to ensuring that pricing to the consumer is internationally competitive at the lowest sustainable cost. For example, with refineries the key question is whether a local refinery can compete with the alternative of importing product in sustainable quantities over the refinery lifecycle. The key lesson, particularly with the recent crude finds is to evaluate new refinery expansion on a commercial basis against import parity.

### 9.2.1.2. Strategic Storage and Pipelines

- Strategic petroleum product storage is a fundamental requirement for all countries to ensure that there is sufficient product to meet the country's demand in the event of an emergency or supply disruption. The level of strategic stock varies per country and is also influenced by their relative crude and refinery positions. The International Energy Program agreement requires each IEA member country to have oil stock levels that equate to no less than 90 days of net imports.

- Pipelines are key distribution mechanisms and are generally managed on a common access, low cost basis either through a consortium of oil companies or a common carrier. Common access, competitive tariffs, private company investment and operation, with Government involvement in tariff structures, security and environmental protection are key issues for Kenya to consider.

### 9.2.1.3. Downstream wholesale business development and retail markets

- Private sector involvement should be encouraged. Local private firms could develop facilities like storage terminals, depots, and petrochemical industries. Private sector firms can develop such projects in consortia and Kenya can encourage such partnerships by offering incentives to the local firms involved in a clear and transparent process.

- Efficiency of operations is important to global competitiveness for downstream operations. A competitive downstream market is critical to the maintenance of a commercially driven economy with access to petroleum products at market related competitive prices. The benchmarked countries illustrate the changing nature of the markets. Globally there has been a change with the reducing dominance of the integrated oil refining and marketing companies and emergence of independent marketers. This has increased the level of competition and diversified the investment in downstream.

The lessons observed have been incorporated into the key supply chain options and recommendations developed within this document.

### 9.2.2. Gas

In order to successfully develop a greenfield gas industry, be it from gas imports or based on indigenous supply, the Government of any country must always consider two key aspects from early stages of Gas Master Planning:

1) Supply and Demand: the need for economic gas pricing and security of gas supply and offtake
2) Infrastructure: the need for gas infrastructure and creation of competition

Many countries have failed on one or both of these aspects and have therefore not been able to grow their gas markets as planned, having to continue to rely on alternatives in the established but more expensive oil industry.

#### 9.2.2.1. Supply and Demand: the need for economic gas pricing and security of gas supply and offtake

Gas use will generally be cheaper, cleaner and more efficient than alternative fuels. Hence the need for economic pricing would be supply driven rather than demand driven, i.e. domestic prices should be high enough in order to promote more gas supply from indigenous gas production or through imports, without the need for subsidies from the Government. In developed gas markets, gas is commonly priced against alternative fuels in different industry sectors (mainly oil products) or in relation to gas market prices where prices are driven by gas supply and demand fundamentals. Developing gas markets often use fixed pricing, which risks being out of the market and receives strong opposition when increases are contemplated or attempted. Nevertheless, if set initially at the right level and well regulated, fixed gas pricing is easier to understand and can work well. Many countries with indigenous reserves have set these initially at very low levels in the hope of promoting gas use and growing demand, only to realise that supply at these prices is not sustainable but difficult to raise.

In order to avoid the issues faced by countries such as India and Malaysia, Kenya should determine a sound and transparent methodology for gas pricing from the onset. With gas supply initially expected to come from imports of LNG, gas prices must reflect international prices and can then be potentially reduced as indigenous production is brought online, bearing in mind that prices still need to be high enough prices to justify domestic production and encourage continued exploration. Prices may not need to be sustained at international price parity as smaller indigenous gas producers may not have an option but to supply domestically. Subsidising gas prices initially is not sustainable and price increases are likely to be challenged. Unlike India and Malaysia, gas prices in Israel are determined through commercial negotiations between buyers and sellers. With several supplying companies, all with access to gas infrastructure, buyers are free to choose their supplier, thereby keeping prices and other supply terms competitive and ensuring security of supply. The key therefore appears to be developing accessible gas infrastructure to enable multiple players to reach the market.

#### 9.2.2.2. Infrastructure: the need for gas infrastructure and creation of competition

Given the right pricing, the development of gas infrastructure (mainly gas pipelines) will be required to meet demand in different locations. The Government’s role in this is critical in order to consider a more holistic view of developing the industry as opposed to one project at a time. Infrastructure will initially and mainly be required for supplying major ‘anchor’ gas projects, such as a large power plant. Industrial demand will take time to develop once larger projects are in place, but if this is anticipated and planned for earlier on, it not only provides assurance for smaller projects but also optimises infrastructure development plans, costing and pricing. Opening up infrastructure access for third parties will be important in providing access to supply and creating competition amongst suppliers. Governments have developed major gas infrastructure based on revenues from other sectors or through loans. As infrastructure projects are generally low risk and hence receive regulated returns, seeking private sector investment should not be too challenging. The Government's role in development is more important from a planning and regulation perspective.

The Kenyan Government would need to have a large role in the planning and development of gas infrastructure. As Kenya is not expected to be as large a gas/LNG exporter as Nigeria, domestic supply obligations for export projects may be small. With the likelihood of potential indigenous gas production to be supplied domestically, domestic gas pricing at economical price levels will be more critical. Gas infrastructure costs should only make up a small portion of the overall end user price. If gas prices are set as such in Kenya, there are considerable benefits to be had in the development of smaller projects in the industrial sector in addition to the larger projects which are expected. With the majority of the gas reserves expected to be located in coastal Lamu, and with a gas demand from the planned conversions and large scale power plant(s) in Mombasa, Kenya can benefit from fast track development of an offshore gas pipeline, as Israel has done.

### *9.2.2.3. Summary of Observations - Learning and implications for Kenya (Gas)*

We discuss the key points arising from our analysis in more detail and provide some lessons from the benchmark countries below:

*Table 9.2: Summary of key midstream and downstream learning points (Gas)*

| Learning Point | Implications for Kenya |
|---|---|
| Supply and Demand: the need for economic gas pricing and security of gas supply and off take | Gas use will generally be cheaper, cleaner and more efficient than alternative fuels. Hence the need for economic pricing would be supply driven rather than demand driven, i.e. domestic prices should be high enough in order to promote more gas supply from indigenous gas production or through imports, without the need for subsidies from the Government. In developed gas markets, gas is commonly priced against alternative fuels in different industry sectors (mainly oil products) or in relation to gas market prices where prices are driven by gas supply and demand fundamentals. Developing gas markets often use fixed pricing, which risks being out of the market and receives strong opposition when increases are contemplated or attempted. Nevertheless, if set initially at the right level and well regulated, fixed gas pricing is easier to understand and can work well. Many countries with indigenous reserves have set these initially at very low levels in the hope of promoting gas use and growing demand, only to realise that supply at these prices is not sustainable but difficult to raise.<br><br>Gas prices in Malaysia are heavily subsidised at around US$5/MMBtu, with 50% of gas demand coming from power generation and 30% from industry. Since 2010 the Government has been planning to remove gas subsidies but has made little progress to date, opting for political gain at the cost of the international development of its national oil company, PETRONAS. Removing subsidies is also important in order to promote more gas production and supply to the domestic market. Malaysia has recently had to turn to imports of LNG, paying international gas prices of around three times the subsidised domestic price. Pakistan is also facing the same issue. Nevertheless, some industrial players have agreed to pay such prices in order to secure gas supply. The Malaysian Government's attempt to increase gas production and supply domestically thus far has been to reduce the petroleum income tax from 38% to 25% and an increase in the reimbursement for a company's original investment from 70% to 100% for production from smaller, deeper and more remote fields.<br><br>India has experienced similar issues to Malaysia, with low domestic gas prices inhibiting the development of indigenous gas production. Prices are currently administered for gas production at US$4.2/MMBtu increased from US$1.8/MMBtu in 2010. Transport costs and prices to end users are also |

| | |
|---|---|
| | regulated and are determined on a cost plus basis. Administered prices are proposed to be increased to US$8.4/MMBtu in 2014 with indexation to international prices with the aim of eventually reaching international price parity. However, there has been strong opposition against price increases and the Government is currently reviewing its options. With the lack of indigenous production and uncertainty as to whether this may change, India increasingly has to rely on internationally priced LNG imports. LNG imports currently account for 35% of total consumption and are largely supplied to industry and fertiliser production, where it is cheaper than oil product alternatives. If LNG is required to meet rising demand in other sectors, domestic prices would have to triple to justify supply. In any case, prices have to be increased in order to encourage more indigenous production and curb the increasing dependence on more costly LNG imports.<br><br>In order to avoid the issues faced by India and Malaysia, Kenya should determine a sound and transparent methodology for gas pricing from the outset. With gas supply initially expected to come from imports of LNG, gas prices must reflect international prices and can then be reduced as indigenous production is brought online with a lower associated cost, bearing in mind that prices still need to be high enough prices to justify domestic supply and encourage continued exploration and production. Prices may not need to be sustained at international price parity as smaller indigenous gas producers may not have an option but to supply domestically. Increasing demand should lead to more competition between indigenous suppliers if the regulatory environment is correctly set, thereby ensuring that gas prices remain competitive. Subsidising gas prices initially is not sustainable and price increases are likely to be challenged. Unlike India and Malaysia, gas prices in Israel are determined through commercial negotiations between buyers and sellers. With several supplying companies, all with access to gas infrastructure, buyers are free to choose their supplier, thereby keeping prices and other supply terms competitive and ensuring security of supply. |
| Infrastructure: the need for gas infrastructure and creation of competition | Given the right pricing, the development of gas infrastructure (mainly gas pipelines) will be required to meet demand in different locations. The Government's role in this is critical in order to consider a more holistic view of developing the industry as opposed to one project at a time. Infrastructure will initially and mainly be required for supplying major 'anchor' gas projects, such as a large power plant. Industrial demand will take time to develop once larger projects are in place, but if this is anticipated and planned for earlier on, it not only provides assurance for smaller projects but also optimises infrastructure development plans, costing and pricing. Opening up infrastructure access for third parties will be important in providing access to supply and creating competition amongst suppliers. Governments have developed major gas infrastructure based on revenues from other sectors or through loans. As infrastructure projects are generally low risk and hence received regulated returns, seeking private sector investment should not be too challenging. The Government's role in the development is more important from a planning and regulation perspective.<br><br>Despite having sub-optimal gas pricing, India and Malaysia have managed to develop a significant gas pipeline transmission and distribution network. This has been mainly through state-owned companies, which own many other assets and are credit worthy, and can therefore easily raise finance for the development of relatively low risk gas infrastructure. Pipeline tariffs are regulated and aim to |

provide the companies with a 'reasonable' rate of return on total costs. India has also developed Access Codes requiring one third of the capacity in both gas pipelines and LNG import terminals to be made available to third-parties with the tariffs for third party users also being subject to regulation.

Similar success in gas infrastructure development has been seen in Turkey, Trinidad and Israel. In Turkey, state owned BOTAS enjoyed monopoly rights on natural gas import, distribution, sales and pricing for over ten years up until 2001. Over this time the market was well developed with supply mainly through imports and end user prices tracking pipeline import prices. In 2001, the market was liberalized, with BOTAs maintaining control of LNG imports, gas transmission and storage facilities. There are currently also 42 wholesaling companies and 63 distribution companies in the country. In Trinidad, state-owned NGC was tasked with the promotion of the natural gas industry and was given the monopoly over the purchasing, selling and distribution of natural gas to industrial and commercial consumers. NGC quickly developed and operated a gas transmission network to supply cheap associated gas to power stations and then to petrochemical plants around the country. NGC went on to lead gas supply negotiations with operators for on sale to domestic customers. However, the market in Trinidad is small, and with significant revenues from a history of oil production as backing, the development of a gas industry was much easier to do.

In Israel the Government had a clear picture of the likely demand centres which was largely based on gas-fired power generation projects. After the system was developed to reach these power plant locations, it was a relatively low cost and a fast implementation process to then connect industrial consumers followed by smaller consumers via gas distribution franchises. The Government was also clear from the outset that the gas industry should work as far as possible on a competitive basis. INGL was given the monopoly on gas transportation but was not allowed to purchase or supply gas itself. Buyers and seller were given access to INGL's transmission pipeline for a regulated fee.

Nigeria, despite holding some of the world's largest reserves of natural gas, has thus far failed to develop a domestic natural gas industry. With very low domestic gas prices of US$1/MMBtu, planned to be increased to US$2/MMBtu, not many gas producers are willing to supply the domestic market. However, with the introduction of plans for Domestic Supply Obligation Policy as part of the 2008 Gas Master Plan, a predetermined amount of gas supply should be available from gas producers. This policy is expected to be included in the long-awaited Petroleum Industry Bill (PIB). Gas supply aside, Nigeria's major problems also lie in a lack of gas infrastructure, to the extent that gas-fired power plants have been developed and have had to be mothballed or delayed coming online due to a lack of gas supply. The Government did little to secure the development of gas infrastructure and is now having to rectify this. Fortunately, the development of gas infrastructure sits outside the controversial PIB and is currently underway, with the hopes that the PIB will be passed and gas will start to be supplied upon completion.

*Source: PwC Consortium Analysis*

# *Environmental and Social Discussion*

# 10. Environmental & Social Discussion

## 10.1. Analysis of the Environmental and Social regulatory and policy framework governing Oil and Gas in Kenya

### 10.1.1. Introduction

This section outlines an analysis of the environmental as well as the social regulatory and policy framework governing the oil and gas sector in Kenya. It identifies various gaps that exist in each legislation discussed in order to recommend areas to be addressed by GoK in the short, medium and long term. Gaps were identified through a consultative process among key stakeholders as well as via literature review.

The major laws, policies, and guidelines governing Kenya's oil and gas sector are summarized below:

*Table 10.1: Kenya's oil and gas key policies, guidelines and legal provisions*

| Key Policies / Laws | Major Provisions |
|---|---|
| Environmental Management and Coordination Act, 1999 (EMCA) | • The National Environment Management Authority (NEMA) is established to exercise general supervision and co-ordination over all matters relating to the environment and to be the principal instrument of Government in the implementation of all policies relating to the environment.<br>• Oil and gas exploration and production infrastructure are listed as projects that require an Environmental Impact Assessment and Audit. The Act prohibits discharge of hazardous substances, chemicals and materials or oil into the environment and outlines basic guidelines on the spiller's liability.<br>• Subsidiary EMCA legislations include:<br>1. EIA/EA Regulations, 2003<br>2. Water Quality Regulations, 2006<br>3. Waste Management Regulations, 2006<br>4. Noise and Excessive Vibration Control Regulations, 2009<br>5. Controlled Substances Regulations, 2007<br>6. Conservation of Biodiversity Regulations, 2006<br>7. Air Quality Regulations, 2008<br>8. Wetlands, River Banks, Lake Shores and Sea Shore Management Regulation, 2009<br>9. Prevention of Pollution in Coastal Zone and other Segments of the Environment) Regulation, 2003<br>10. Fossil Fuel Emission Control Regulations, 2006<br>11. The Environmental Management and Coordination<br>12. (Deposit Bonds) Draft Regulations, 2014 |
| Energy Act, 2006 | • The Energy Regulatory Commission (ERC) is the lead agency created under the Act and one of its powers is to formulate, enforce and review Environmental, Health and Safety (EHS) and quality standards for the energy sector in coordination with other statutory authorities. |

| Key Policies / Laws | Major Provisions |
|---|---|
| Occupational Safety and Health Act, 2007 (OSHA) | • The purpose of this Act is to secure the safety, health and welfare of persons at work and protect persons other than persons at work against risks to safety and health arising out of, or in connection with, the activities of persons at work. |
| The Wildlife Conservation and Management Act, 2013 | • It requires that no person shall undertake oil or gas exploration and extraction without the consent of the Cabinet Secretary, and with the prior approval of the National Assembly.<br>• It prohibits discharges of any hazardous substances or waste or oil into a designated wildlife area contrary to the provisions of this Act and any other written law |
| Petroleum Exploration, Development and Production Bill, 2014 | • Provides a framework for the contracting, exploration, development and production of petroleum; and cessation of upstream petroleum operations, to give effect to relevant articles of the Constitution in so far as they apply to upstream petroleum operations and connected purposes.<br>• The Bill establishes the Upstream Petroleum Regulatory Authority which will also coordinate environment, health and safety issues related to upstream exploration and production of oil and gas. |
| The Evictions and Resettlement Procedures Bill, 2012 | • Sets out appropriate procedures applicable to forced evictions; protection, prevention and redress against forced eviction for all persons occupying land including squatters and unlawful occupiers. |
| The Climate Change Bill, 2014 | • Establishes the National Climate Change Council whose main function is to advise the national and county Governments on legislative and other measures necessary for mitigating and adapting to the effects of climate change.<br>• Provides the legal and institutional framework for the mitigation and adaption to the effects of climate change; to facilitate and enhance response to climate change; to provide for the guidance and measures to achieve low carbon climate resilient development and for connected purposes. |
| Prevention and Control of Marine Pollution Act, 2014 | • This Bill gives effect to the Constitution, international treaties and conventions on marine pollution, provides for the prevention, mitigation and control of pollution of the sea from ship transport operations, preparedness and response for pollution emergencies arising from ship transport operation, liability and compensation for pollution damage arising from shipping transport operations and pollution damage resulting from exploration and exploitation of seabed mineral resources. |
| National Marine Spills Contingency Plan | • National Plan to combat pollution of the sea by oil and other noxious and hazardous substances. |
| Oil Dispersant Use Policy | • KMA policy to control the use of oil dispersants. |

*Source: PwC Consortium Analysis*

***International Environmental Agreements of Importance to Petroleum Sector -*** The Government of Kenya has ratified and is currently domesticating the following Multi-lateral Environmental Agreements (MEAs) which are relevant to the sector:

- *United Nations Framework Convention on Climate Change (UNFCCC):* The Climate Change Bill, 2014 is before parliament for enactment. The EMCA, 1999 and the Air Quality Regulations, 2008 provide standards for air emissions from industries, vehicles and other sources.
- *United Nations Convention on the Law of the Sea (UNCLOS):* the GoK has developed the Marine Pollution (Shipping Operations) Bill, 2014 for enactment by parliament.
- Convention on Biological Diversity: domesticated through the EMCA, 1999, and the Conservation of Biodiversity Regulations, 2006.
- *Convention on Wetlands of International Importance especially as Waterfowl Habitat (Ramsar Convention):* GoK has enacted the Wetlands, River Banks, Lake Shores and Sea Shore Management Regulations, 2009 and the Water Quality Regulations, 2006 to fulfill the requirements of this convention.
- *International Convention on Oil Pollution Preparedness, Response and Cooperation, 1990 (OPRC 90):* Kenya Maritime Authority (KMA) has also developed the National Marine Spills Contingency Plan and Oil Dispersant Use Policy to domesticate this international agreement.

### 10.1.2. Gaps in the existing environmental and institutional legislative framework and key recommendations

To identify the existing gaps, the consultation of key stakeholders included ERC, Ministry of Environment, Water and Natural Resources, NEMA, Ministry of Energy and Petroleum, KPC, National Oil Corporation of Kenya (NOCK), Kenya Maritime Authority (KMA), National Disaster Operation Centre, private oil and gas companies and civil society organizations. Our review of the existing environmental legislative framework as well as the stakeholder discussions revealed the following policy and legal gaps.

- ***Legal and Policy Gaps***

GoK has not officially published environmental policy and regulations in the following key areas:

1. *General Strategic Environmental and Social Assessment (SESA) guidelines and comprehensive regulations:* The NEMA draft guidelines require public and stakeholder participation in order to improve on SEA resource requirements (human, financial and technical), procedures, standards and timelines.

2. *Petroleum Sector SEA/ EIA/ EA Technical Manual Guidelines:* A draft of SEA guidelines for the sector is currently being developed by ERC. The draft guidelines produced through a consultative process by the ERC in consultation with the NEMA have not been finalized. These guidelines need to be finalized and published after including the upstream and mid-stream activities which are generally lacking in the existing draft. Since ERC will not be regulating EHS issues in the upstream, it may be necessary this process to be transferred and accomplished by NEMA with the support of various lead agencies.

   The private sector through PIEA has also made an effort of developing EIA guidelines for downstream activities. PIEA guidelines require major review to include upstream (onshore and offshore) and mid-stream activities of oil exploration and production activities. The guidelines also need to be adopted and officially published by the GoK/ NEMA for them to be applied by all petroleum sector stakeholders and professionals in the Country.

3. *Social Impact Assessment (SIA) Guidelines:* SIA involves the analysis, monitoring and the managing of the social consequences of development strategies/ policies, plans, programs and projects. Social issues that need to be emphasized in the existing EIA/EA regulations include assessment of impacts on people's way of life, culture and traditions, community, political systems, health and wellbeing, property rights, fears and aspirations. Currently, there exists a policy gap on information required during the EIA process on potential socio-cultural, gender-specific impacts and opportunities of the oil and gas sector – including how men, women, youths and children may experience risks and benefits from the sector.

4. *Petroleum Sector Environment, Health, Safety (EHS) Guidelines*: for upstream, mid-stream and downstream activities and operations. These guidelines do not exist to date leaving a major gap in the sector in the form of the high risks associated with the oil and gas facilities work environment.

5. *Hazardous Waste Management and Gas Flaring Legal Procedures and Environmental Standards:* There are no specific legal guidelines or technical manuals on disposal of upstream oilfield waste from drilling activities, oil wells, offshore waste and gas flaring. Such guidelines need to be developed to set out procedures for responsibilities and enforcement, waste characterisation and classification, waste manifesting and tracking, standards of oilfield waste management facilities, waste storage and transfer, biodegradation, thermal treatment, use of oil by-products, management of oilfield landfills, importation and export of oilfield wastes, treatment and waste transport by pipelines. There is basically no oilfield waste user's guide. Following the devolution of waste management to County Governments, there is lack of general procedures on capacity building of the new institutions on matters related to environmental protection and conservation especially in establishing oil field waste disposal facilities. The law does not provide a monitoring guide for upstream oil field wastes discharge by oil and gas production facilities.

6. *Environmental Charges/ Fees:* The EIA License fee of 0.1% of total project investment is too high for investors in the petroleum sector. Annual "Effluent Discharge License" (EDL) legal requirements for applications and the high rates of fees charged by NEMA have also proved to be tedious, inconveniencing and expensive for most petroleum businesses. Charges should be reviewed and should aim to balance environmental conservation and legal and economic/financial considerations.

7. *Decommissioning of Facilities and Restoration:* Section 93 of the EMCA, 1999 prohibits discharge of hazardous substances, chemicals and materials or oil into the environment and outlines basic guidelines on the spiller's liability. However, there exists no specific legislation as envisaged in this section to handle *oil* and gas environmental pollution. The *"polluter-pays- principle"* hangs in law with no specific guidelines manual on assessment of environmental damages.

8. *Eviction and Resettlement Legal Guidelines:* To deal with land acquisition and social impacts; there is need for finalizing the existing drafts to ensure high environmental and social performance standards for this sector in public, private and community land.

9. *Air Quality Standards:* There are limited environmental standards and guidelines for upstream oil drilling and mid-stream processing activities to meet international air quality thresholds.

10. *Environment Liability Policy:* The Energy Bill, 2014 and the Petroleum Act, 2014 requires that all operators shall have an environmental liability policy as shall be prescribed by the Cabinet Secretary in charge of energy. The two laws require that all upstream, mid-stream and downstream developments shall comply with the Environmental Management and Co-ordination Act, 1999 and the Occupational Safety and Health Act, 2007.

- ***Environmental Provisions in Upstream Exploration and Production Sharing Contracts:***

All contracts / agreements on upstream exploration under the draft bill currently before parliament have clauses that require the contractor to comply to environmental laws and also apply the best environmental, health and safety practices to protect and conserve the physical and ecological environment (fauna and flora), national parks and nature reserves, properties and infrastructure, water sources, agricultural areas, forests, fisheries and any other natural resources when carrying out upstream petroleum operations. The law requires that once an agreement is signed, the contactor should immediately undertake a strategic environmental and social impact assessment and obtain SEA and EIA licences from the National Environmental Management Authority. The contractor is expected to conserve petroleum resources by preventing and minimizing wastage of petroleum, protection of correlative rights and maximization of ultimate economic recovery. The contractor is responsible for site restoration or environmental damage to the extent the same pertains solely and directly to upstream petroleum operations conducted pursuant to the contract. In case of pollution resulting directly from the gross negligence or willful misconduct of the contractor, the contract provides that the cost of clean-up and repair activities shall be borne by the contractor and shall not be included as petroleum costs under the contract except for decommissioning costs. The Bill further prohibits venting and flaring of oil and natural gas except with the authorisation of the Upstream Petroleum Regulatory Authority and NEMA during production testing or for emergency reasons.

It is proposed that contract clauses on environment shall be reviewed by highly experienced and competent legal environmental experts at the Attorney General's office before final contracts / agreements are signed. The Petroleum (Exploration and Production) Act requires some amendments for purposes of realignment to the national existing environmental laws. Environmental monitoring, compliance and enforcement are facing challenges due to limited financial, technical and human capacity of NEMA, County Governments and other relevant Government Agencies like Kenya Forest Service (KFS), Kenya Maritime Authority (KMA), Water Resource Management Authority (WARMA) and Kenya Wildlife Service (KWS).

- ***Access to Land for Petroleum Exploration and Production:***

The land tenure system for most of the land in basins with oil and gas potential is communal. Thus, land is collectively owned by the residents and managed, on behalf of the community, by the County Governments. Land adjudication to various communities / clans is yet to be undertaken in most areas, thus pasture and settlement lands have no legal land ownership documents. This has been the main cause of boundary-related conflicts and inter-tribal and inter-clan clashes.

The Petroleum (Exploration and Production) Act (CAP 308), requires that whenever, in the course of carrying out petroleum operations, any disturbance of the rights of the owner or occupier of private land, or damage to the land, or to any crops, trees, buildings, stock or works therein or thereon is caused, the contractor (the person with whom the Government concludes a petroleum agreement with) shall be liable on demand to pay to the owner or occupier such compensation as is fair and reasonable having regard to the extent of the disturbance or damage and to the interest of the owner or occupier in the land. This Act does not give guidelines on access to public and community lands in terms of compensation to the Government or County Governments.

The Energy Bill, 2014 requires that in the event of a fire, explosion, oil spill, injury or fatality occurring in the course of operating a petroleum logistics facility, transportation or sale of petroleum, either by accident or through negligence, the operator or person transporting or selling the petroleum shall forthwith clean up the polluted or damaged environment, at the operator's own expense, to the satisfaction of the licensing authority and any other relevant authority. Every business is also required to put in place an oil clean-up plan in case of an emergency.

- ***Sharing of Petroleum Resources and Opportunities for Community Economic Empowerment:***

The current draft petroleum law (Petroleum Exploration, Development and Production Bill, 2014) proposes that the Government share of revenue from oil and gas shall be apportioned between the National Government, the County Government and the local community at a ratio of 75:20:5, respectively. The local community's share shall be payable through the County Government. While all public land and minerals belong to the people of Kenya collectively as a nation, this proposed sharing formula will require public consultation prior to its final enactment into law. Each County Government shall legislate on the prudent utilisation of the funds received under this section for the benefit of present and future generations. Public consultations of the communities in Turkana County where upstream activities are at their most advanced in Kenya, reveals that the stakeholders are negotiating for a local formula where the county revenue obtained from petroleum activities be allocated 60% for County-wide development projects and 40% within the local community/ sub-county where revenue is generated. This conflict is due to unclear National Guidelines on Revenue sharing from natural and mineral resources. There are also conflicts in opportunity sharing, especially available skilled, semi-skilled and un-skilled job opportunities and relevant goods and services supply contracts.

The Community Land Bill, 2013 proposes that every investor on community land shall spend not less than thirty percent of the net income in any or some of the following: (a) provision of services to the community; (b) laying infrastructure in the community; (c) education and capacity building; or (d) payment of royalties. This benefit sharing formula conflicts with the draft petroleum law (Petroleum Exploration, Development and Production Bill, 2014) and may have some constitutional loopholes that need to be sorted out before the law is enacted. There is also need to harmonise the legal institution that should enter agreements on community land leases for oil and gas exploration.

- ***Private Sector Initiatives:***

The Petroleum Institute of East Africa (PIEA), launched on 8th July 1999, is one of the active and effective private sector initiatives that provides a forum as a focal point for interaction between all interested parties in the oil and gas industry. It is a non-profit organization with over 70 members of different categories. The PIEA's mission is to provide a forum for expertise and excellence in the oil industry in the East African region with the aim of promoting professionalism and free enterprise in petroleum business supported by the highest business and operating standards, and adherence to Environment, Health and Safety ideals. One of its core functions is to lobby for the enactment of comprehensive guidelines necessary for the advancement and safety for the Petroleum Industry.

Another positive sector development initiative is the establishment of the School of Petroleum Studies which was incorporated in 2007 as a wholly owned subsidiary of PIEA with the prime objective of offering specialized training with a curriculum focused on downstream, midstream and upstream oil and gas. It has an international certification as a Training Provider by the Energy Institute - the global membership body for the energy industry. It offers courses tailored for the petroleum sector which include financial, management and operations of oil and gas facilities, Information Technology, policy and law, EHS, quality standards, human resource management, transportation, marketing and international trade.

- ***Development of Petroleum Road Transportation Safety Systems:***

The country has experienced several road accidents involving petrol tankers that have led to loss of many lives in the past three decades. Following the collapse of the National Road Safety Council in the mid-eighties, there has been very little formal co-ordination between various ministries, agencies and the private sector involved in road safety. The participation of private sector and civil society organizations has been limited as there lacks a legal framework for their effective involvement and partnership with the Government. Through the support of the Ministry of Transport and supported by the GoK/SIDA Roads 2000 Project, the Government of Kenya published a draft National Road Safety Action Plan of 2005-2010. As a follow-up on this Action Plan, the National Transport and Safety Authority (NTSA) was established through an Act of Parliament; Act Number 33 on 26th October 2012. The objective of forming the Authority was to harmonize the operations of the key road transport departments and help in effectively managing the road transport sub-sector and minimizing loss of lives through road accidents. NTSA currently co-ordinates all activities' of persons and organisations dealing in matters relating to road safety including prevention programmes to reduce accidents related with petrol tankers.

Road crashes are a major public health problem that imposes a range of socio-economic burdens that may affect sustainable development of countries and also the achievement of Millennium Development Goals especially in Africa and other developing countries. In responding to this global epidemic, the UN declared 2011-2020 as the UN *Decade of Action for Road Safety*. In January 2010, TOTAL and the World Bank entered into a partnership to use their combined knowledge and experience in Africa to improve the safety of roads. The two partners through technical support of UN-WHO launched the *Africa Road Safety Corridor Initiative* (ARSCI) on 27 April 2011 in Malaba town on the Kenya / Uganda border. An NGO, *Safe Way Right Way*, was subsequently established to mobilise private sector and implement ARSCI project goals.

The purpose of Safe Way Right Way is to mobilise private sector firms and other actors in promoting road safety on the Northern Transport Corridors in tandem with World Health Organisation's Safe System Approach and based on self-regulation road safety. The Northern Corridor links the port city of Mombasa with Nairobi, Kampala, Kigali and Bujumbura, and is the primary access for part of Central African Republic, Eastern Democratic Republic of Congo, Sudan and Southern Ethiopia. Safe Way Right Way has managed to bring together expertise and best practices from a range of partners representing diverse sectors, which have a singular objective of contributing towards the reduction in the number of road crashes on the corridor. The NGO operates on five (5) pillars: *Road Safety Management, Safer Roads and Mobility, Safer Vehicles, Safer Road Users,* and finally *Post Crash Response*. Some petroleum companies, especially those with road-based distribution vehicles in the downstream, are supporting this initiative to reduce the oil and gas tanker accidents in the country. Some of the achievements are Black Spot Mapping in the whole country, capacity building of drivers and young generation / school children on road safety issues as a long term sustainability strategy.

The private petroleum sector actors have further established highway safety programmes to reduce the impact and losses on road accidents involving petrol tankers. The Petroleum Institute of East Africa has developed the Highway Emergency Response Plan (HERP) and the Petroleum Drivers Handbook, which make up the Petroleum Road Transportation Safety Systems. PIEA has also been undertaking capacity building in the petroleum sector to ensure road safety in the East African region. These initiatives need to me mainstreamed within the National Government disaster response system for efficiency and effectiveness. It also requires technical and financial support from the National Government through the National Transport and Safety Authority (NTSA).

- ***Institutional and organizational Set-ups:***

There is no specific department or section in Kenya's National Environmental Management Authority (NEMA) clearly designated to handle oil and gas environmental, health and safety issues and implementation of emergency response programs for the oil and gas industry in case of an emergency. NEMA also has very limited staff specialized in petroleum and environmental engineering issues who are able to undertake technical reviews of EIA reports from the sector and provide the advice expected by the oil and gas exploration companies. The Prevention and Control of Marine Pollution Bill, 2014 conflicts with the roles of KMA and NEMA in the EIA process and environmental compliance and enforcement procedures.

- ***Strategic Environmental and Social Assessment (SESA):***

The petroleum sectorial policies, programs and plans have not undergone a Strategic Environmental and Social Assessment (SESA) process that will develop comprehensive Action/ Management and Monitoring Plans. Since the planned infrastructural projects in the upstream, mid-stream and downstream will have local, regional and trans boundary adverse and irreversible environmental and social impacts, the above documents will require formulation and implementation in the short term to protect and conserve the environment and also protect the local communities.

- ***Development of an Environmental Management and Information System (EMIS):***

NEMA has not developed this system to the expected levels due to limited resources. EMIS provides a complete, largely automatic, fully integrated, state-of-the-art ICT solution for the environmental management: planning, assessment, compliance monitoring and impact assessment as well as emergency management. This will provide NEMA and other lead agencies with an information technology solution for tracking environmental data for the emerging petroleum sector as part of their overall Environmental Management Systems (EMS).

- ***National Environmental Monitoring Laboratory:***

This facility needs to be established to take a leading role in a broad range of specialized and internationally accredited analytical laboratory services, including sample characterization, quality assurance, technical consulting on laboratory services to the private sector. This will not only support the petroleum sector, but also quality management in all GoK environmental monitoring, assessment and research programs across the country.

- ***Oil Spill Preparedness, Emergency Response and Crisis Management:***

The oil spill preparedness, emergency response and crisis management are disjointed and ill- equipped in the country. There is dire need for collection of key information for development of a National Oil Spill Contingency Plan and actions to strengthen the GoK's capacities in these areas. This National Oil Spill Contingency Plan needs to be harmonized with the National Disaster and Emergency Response Plan especially on chain of command in case of an emergency onshore and offshore. There is also need for consultation and harmonization on the GoK agency that should enforce the *"polluter pays principle"* in Upstream, Mid-Stream and Downstream when damage is caused by oil spillage and other forms of pollution.

- ***Clean Production Technologies:***

The regulations have limited mechanisms of institutionalizing energy efficiency in the oil and gas sector. The main aim should be to reduce cost and enhance competitiveness and profitability while promoting a clean and healthy environment in the petroleum sector.

## 10.2. Environmental and Social regulatory and policy review and benchmarking summary

Environmental legislation in Kenya is provided in over 77 statutes. The Environmental Management and Coordination Act (EMCA) was enacted in 1999 as the main and comprehensive framework law to guide the environmental management systems. The Energy Act (2006) created the Energy Regulatory Commission which was mandated to formulate, enforce and review environmental and health and safety standards for the energy sector in cooperation with other agencies. The Occupational Safety and Health Act (2007) (OSHA), protects the safety, health and welfare of persons at work, as well as third parties at risk as a result of activities by persons at work.

There are several gaps in Kenya's existing environmental and social framework as it relates to the oil and gas sector. There is no specific department within the National Environmental Management Authority designated to handle oil and gas environmental, health and safety and emergency response issues.

Additionally, upcoming upstream oil and gas production areas are currently not included in the list of projects required to undergo Environmental Impact Assessments. There are also no specific legal guidelines or technical procedures and standards on the disposal of upstream oilfield and offshore waste and gas flaring.

Guidelines on gas flaring as well as waste classification, tracking, storage and transfer, and treatment, among others, need to be developed. Waste management has been delegated to County Governments post-devolution and there is a need to establish capacity building procedures for the new institutions in terms of oil field waste disposal and related issues.

There also exists a major gap in handling social impacts related to human evictions, compensation and resettlements.

In a majority of countries studied, a sufficiently appropriate, but largely theoretical, environmental policy and legal framework is in place. However, the effectiveness of this framework tends to be compromised by the lack of a sufficiently organized administrative structure that enables efficient regulatory compliance and enforcement. Additionally, the human and financial resources needed for effective environmental governance are generally lacking. Institutionally, most countries have a dedicated institution in place for managing the environmental and social impacts of the oil and gas industry; this is either a ministry of environment, or a similar institution.

Most countries have some form of Environmental Impact Assessment process that has been incorporated within their legal and regulatory framework. However, much of the emphasis of the EIA process appears to be directed toward approval of oil and gas projects rather than reflecting a life-cycle management approach to environmental and social issues. Evidence of this effect is that most countries make use of insufficient— and sometimes totally absent—control and enforcement mechanisms during the post-EIA approval phase. Environmental monitoring and restoration mechanisms are either weak or not enforced.

Regarding public consultation and involvement, Governments may consult about oil and gas activities during the EIA process, but they disclose limited information to the public and affected stakeholders. Consultation is more about informing stakeholders about proposed oil and gas projects than involving them in project-related decisions. Additionally, there are significant barriers to the disclosure of information about oil and gas projects and the natural and social environments in which they occur. Most Governments lack a commitment to establish and implement a centralized information system, whether electronic or otherwise.

In less than half of the countries studied, Governments pay little or no attention to issues regarding liability and decommissioning of oil and gas facilities. Efforts to involve the private sector in applying internationally accepted good environmental practices to minimize the impacts of oil and gas development could also be improved.

With strongly increased petroleum exploration activity and the potential for petroleum production over the next three to four years, the volume of activity in the Government of Kenya's petroleum sector is expected to multiply. Increasingly activities will take place in environmentally sensitive and technologically complex areas, which will dramatically increase the level of expertise required in the GoK. The importance for the GoK to be able to extract optimal revenues from this opportunity, to adequately forecast and manage revenues, as well as manage the potential macro-economic, social, and environmental consequences and the impact on economic development justify a significant capacity building effort in the GoK along all aspects of the extractive industries value chain.

The GoK recognises that petroleum development in Kenya is about more than petroleum alone. In order to get the best deals that are best managed for sustainable development, it is crucial to support growth in domestic institutional competences, promote domestic businesses, increase employment across the country, improve infrastructure to support expanded economic activities, and increase access to training and education, while minimising adverse social and environmental impacts.

## 10.3. Oil Development Options Environmental and Social Impacts

Based on the discussion of potential oil development options, we present in the table below selected potential environmental impacts and mitigation measures the Government can consider.

*Table 10.2: Oil options environmental and social impacts*

| Parameter | Crude Oil Pipeline | Product Pipeline | Storage Terminal | Refinery |
|---|---|---|---|---|
| **Air** | · Dust during construction/laying of pipes<br>· Release of VOCs in case of leaks and spills for above ground pipes | · Dust during construction/laying of pipes<br>· Release of VOCs in case of leaks and spills for above ground pipes | · Emission of VOCs<br>· Emission of exhaust and flue gases ($CO_2$, NOx, CO) from equipment and transportation trucks or ships/vessels<br>· Air pollution in case of fires and explosions hazards<br>· Destruction/loss of biodiversity due to exposure to acid rain, contaminated soil, ground water and surface water.<br>· Occurrence of occupational hazards/work accidents<br>· Exposure of workers and the neighboring communities to potential inhalation hazards<br>· Occurrence of confined space hazards<br>· Visual impacts | · Emissions of VOCs, hydrogen, methane, polycyclic aromatic hydrocarbons (PAHs), Inorganic gases)<br>· Emission of Sulphur oxides (SOX)<br>· Production of Particulate Matter (PM)<br>· Production of Green House Gases<br>· Exposure of the neighboring communities to potential inhalation hazards<br>· Occupational exposure hazards may occur<br>· Air pollution in case of fires and explosion hazards<br>· Destruction/ loss of biodiversity due to exposure to acid rain, contaminated soil, ground water and surface water.<br>· Occurrence of work accidents<br>· Creation of asphyxiating conditions |
| **Water** | · Surface water quality may be impacted by ground disturbance that causes localized erosion and/or sedimentation during laying of the pipe<br>· Contamination of the nearby surface or groundwater systems.<br>· Leaks and spills into water bodies<br>· Potential risk for aquatic animals<br>· Impact on water biology<br>· Differential heating of water | · Leaks and spills into water bodies<br>· Contamination of the nearby surface or groundwater systems.<br>· Potential risk for aquatic animals<br>· Impact on water biology | · Contamination from spills caused by overfilling of vessels and tanks<br>· Loss of ecology<br>· Inefficient use of water<br>· Contamination of storm water<br>· Accidental release of contaminated waste water into ground or surface water resources<br>· Contamination during transportation by leaks, massive spillages, fires and explosions | · Contamination of surface and ground water by waste water<br>· Unreliable use of clean/fresh water resources<br>· Contamination from spills caused by overfilling of vessels and tanks<br>· Loss of ecology for example through discharge of high temperature water into the aquatic environment<br>· Contamination during transportation by leaks, massive spillages, fires and explosions |
| **Soil** | · Soil structure disturbance and compaction<br>· Leaks and spills into the soil<br>· The potential risks to human health and ecology<br>· The economic liability that it may pose to the polluter/business owners<br>· Heat impact on soil biology | · Soil structure disturbance and compaction<br>· Leaks and spills into the soil<br>· The potential risks to human health and ecology<br>· The economic liability that it may pose to the polluter/ business owners<br>· Impact on soil biology | · Contamination from spills caused by overfilling of vessels and tanks<br>· Loss of ecology<br>· Soil erosion<br>· Contamination during transportation outside the facility through spills, leaks | · Soil compaction<br>· Soil erosion<br>· Contamination during transportation outside the facility through spills, leak<br>· Contamination caused by spills from overfilled vessels and tanks |
| **Flora and Fauna** | · Cutting down of vegetation<br>· Potential risk of fire upon ignited leakages<br>· Cut off animal routes when the | · Cutting down of vegetation<br>· Potential risk of fire upon ignited leakages<br>· Cut off animal routes when the | · Cutting down of vegetation<br>· Potential risk of fire upon ignited leakages<br>· Cut off animal routes when the pipes are wall-secured | · Cutting down of vegetation<br>· Potential risk of fire upon ignited leakages<br>· Cut off animal routes when the pipes are wall-secured<br>· Loss of breeding grounds |

| Parameter | Crude Oil Pipeline | Product Pipeline | Storage Terminal | Refinery |
|---|---|---|---|---|
| | pipes are wall-secured<br>· Loss of habitats<br>· Risk of burns from the super-heated oil<br>· Loss of breeding grounds<br>· Loss of habitats | pipes are wall-secured<br>· Loss of breeding grounds<br>· Loss of habitats | · Loss of breeding grounds<br>· Loss of habitats<br>· Risk of fires | · Loss of habitats<br>· Risk of fires |
| **Hazardous Material** | · • Pose potential for release of petroleum based products, such as lubricants, hydraulic fluids, or fuels during their storage, transfer, or use in equipment. | · Pose the potential for release of petroleum based products, such as lubricants, hydraulic fluids, or fuels during their storage, transfer, or use in equipment. | · Pose the potential for release of petroleum based products, such as lubricants, hydraulic fluids, or fuels during their storage, transfer, or use in equipment. | · Pose the potential for release of petroleum based products, such as lubricants, hydraulic fluids, or fuels during their storage, transfer, or use in equipment. |
| **Waste** | · Compromised aesthetic value from pipe cuttings and spoils<br>· Earth overburden from the trench digging | · Compromised aesthetic value from pipe cuttings and spoils<br>· Earth overburden from the trench digging | · Contamination of the environment with spills, cleanup materials and oil.<br>· Accidental release of hazardous waste to air, soil and water resources due to poor storage and poor implementation of waste management strategies<br>· Environmental pollution due to mishandling of hazardous waste | · Accidental release of hazardous waste to air, soil and water resources due to poor storage and poor implementation of waste management strategies<br>· Contamination of soil, ground and surface water sources through the use of landfills<br>· Environmental pollution due to mishandling of hazardous waste |
| **Noise** | · Occupational impact to the workers<br>· Acoustic impact to wildlife | · Occupational impact to the workers<br>· Acoustic impact to wildlife | · Increased noise from transportation trucks and operational machinery disrupts the communities activities and biodiversity patterns<br>· Massive noise pollution in the case of fires and explosions | · Increased noise from transportation trucks and operational machinery disrupts the communities activities and biodiversity patterns<br>· Massive noise pollution in the case of fires and explosions<br>· Exposure of workers to harmful noise levels |
| **Occupational, Health and Safety Issues** | · Accidental fires<br>· Release of hazardous compounds into the soil and water in case of leakages<br>· Fugitive dust during construction | · Accidental fires<br>· Release of hazardous compounds into the soil and water in case of leakages<br>· Fugitive dust during construction | · Roll over<br>· Fires and explosions<br>· Chemical hazards<br>· Confined spaces<br>· Contact with cold surfaces<br>· Moving machinery<br>· Falls<br>· Falling objects | · Fires and Explosions<br>· Chemical Hazards<br>· Confined Spaces<br>· Contact with Cold surfaces<br>· Moving Machinery<br>· Falls<br>· Falling Objects |
| **Community Health and Safety** | · Security<br>· General site hazards<br>· Diseases<br>· Traffic safety<br>· Fires and explosions | · Security<br>· General site hazards<br>· Diseases<br>· Traffic safety<br>· Fires and explosions | · Security<br>· General site hazards<br>· Diseases<br>· Traffic safety<br>· Fires and explosions | · Security<br>· General site hazards<br>· Diseases<br>· Traffic safety<br>· Fires and explosions |

*Source: PwC Consortium Analysis*

*Table 10.3: Oil options environmental and social impacts mitigation measures*

| Parameter | Crude Oil Pipeline | Product Pipeline | Storage Terminal | Refinery |
|---|---|---|---|---|
| **Air** | · Monitor pressure losses in filters and replace as appropriate<br>· Use adequately sized distribution pipework designed to minimize pressure losses<br>· Do not mix high volume low pressure and low volume high pressure loads. Decentralize low volume high-pressure applications or provide dedicated<br>· Maximize energy Efficiency and design facilities for lowest energy use to reduce air emissions and evaluate cost effective options for reducing emissions that are technically feasible.<br>· Collection of vapors through air extractors and subsequent treatment of gas stream by removing VOCs with control devices such as condensers or activated carbon absorption;<br>· Collection of vapors through air extractors and subsequent treatment with destructive control devices such as: Catalytic Incinerators, Thermal Incinerators and enclosed oxidizing flares used to convert VOCs into CO2 and H2O by way of direct combustion | · Monitor pressure losses in filters and replace as appropriate<br>· Use adequately sized distribution pipework designed to minimize pressure losses<br>· Do not mix high volume low pressure and low volume high pressure loads. Decentralize low volume high-pressure applications or provide dedicated<br>· Maximize energy Efficiency and design facilities for lowest energy use to reduce air emissions and evaluate cost effective options for reducing emissions that are technically feasible.<br>· Collection of vapors through air extractors and subsequent treatment of gas stream by removing VOCs with control devices such as condensers or activated carbon absorption;<br>· Collection of vapors through air extractors and subsequent treatment with destructive control devices such as: Catalytic Incinerators, Thermal Incinerators and enclosed oxidizing Flares set to convert VOCs into CO2 and H2O by way of direct combustion | · Installation of secondary emissions controls<br>· Establishing a procedure for periodic monitoring of pipes, valves, seals, tanks and other infrastructure components and subsequent maintenance or replacement of components as needed.<br>· Provision of appropriate Personal Protective Equipment for the workers<br>· Promotion, development and increased use of renewable forms of energy<br>· Implementation of source gas reduction measures<br>· Job safety analysis or comprehensive hazard<br>· or risk assessment<br>· Worker training, work permit systems, use of personal protective equipment (PPE), and toxic gas detection systems with alarms.<br>· Implementation of confined space entry procedures<br>· Preparation and implementation of an Emergency Management Plan prepared with the participation of local authorities and potentially affected communities.<br>· Protection and enhancement of sinks and reservoirs of greenhouse gases;<br>· Installation of natural visual barriers such as vegetation. | · Use of low-NOX burners to reduce nitrogen oxide emissions.<br>· Implementation of source gas reduction measures<br>· Installation of high integrity instrument pressure protection systems, to reduce over pressure events<br>· Locating flare at a safe distance from local communities and the workforce including workforce accommodation units<br>· Minimize SOX emissions through desulfurization of fuels<br>· Using high efficiency sulfur recovery units to recover sulphur from tail gases<br>· Install mist precipitators (e.g. electrostatic precipitators or brink demisters ) to remove sulfuric acid mist<br>· Use of particulate emission reduction techniques during coke handling (keep it constantly wet, store it under enclosed shelters etc.)<br>· Carbon financing, capture and storage technologies;<br>· Protection and enhancement of sinks and reservoirs of greenhouse gases;<br>· Promotion, development and increased use of renewable forms of energy<br>· Job safety analysis or comprehensive hazard<br>· or risk assessment<br>· Worker training, work permit systems, use of personal protective equipment (PPE), and toxic gas detection systems with alarms.<br>· Implementation of confined space entry procedures<br>· Preparation and implementation of an Emergency Management Plan, prepared with the participation of local authorities and potentially affected communities. |
| **Water** | · There should be a spill prevention and control plan<br>· Where appropriate, spill control and response plans should be developed in coordination with the relevant local regulatory agencies | · There should be a spill prevention and control plan<br>· Where appropriate, spill control and response plans should be developed in coordination with the relevant local regulatory agencies | · Application of effective spill prevention and control measures<br>· Ensuring that new USTs are sited away from wells, reservoirs and other source water protection areas and floodplains, and are maintained to avoid contamination<br>· Providing an alternative water supply to replace, a contaminated groundwater supply | · Application of waste water treatment techniques<br>· Regular maintenance and inspection of maintenance and storage equipment to prevent and avoid accidental leakages.<br>· Water use efficiency to reduce the amount of wastewater generation and wastage<br>· Installation of gauges on tanks to measure |

| Parameter | Crude Oil Pipeline | Product Pipeline | Storage Terminal | Refinery |
|---|---|---|---|---|
| | | | well<br>· Preventing uncontrolled releases of hazardous materials or uncontrolled reactions that might result in fire or explosion | volume inside to avoid spillage<br>· Application of effective spill prevention and control measures<br>· Preventing uncontrolled releases of hazardous materials or uncontrolled reactions that might result in fire or explosion |
| **Soil** | · Regular monitoring and installation of leak detectors<br>· Controlling the release of hazardous materials, hazardous wastes, or oil to the environment<br>· contaminated soil identification and correction to avoid further releases and associated adverse impacts<br>· Contaminated soils should be managed to avoid the risk to human health and ecological receptors. The preferred strategy for soil is to reduce the level of contamination at the site while preventing the human exposure to contamination. | · Regular monitoring and installation of leak detectors<br>· Controlling the release of hazardous materials, hazardous wastes, or oil to the environment<br>· contaminated soil identification and correction to avoid further releases and associated adverse impacts<br>· Contaminated soils should be managed to avoid the risk to human health and ecological receptors. The preferred strategy for soil is to reduce the level of contamination at the site while preventing the human exposure to contamination. | · Installation of gauges on tanks to measure volume inside<br>· Biological, chemical and physical treatment<br>· Clearly identifying and marking hazardous areas | · Design and construction of wastewater and hazardous materials storage containment basins with impervious surfaces to prevent infiltration of contaminated water into soil<br>· Installation of gauges on tanks to measure volume inside<br>· Clearly identifying and marking hazardous areas |
| **Flora and Fauna** | · To avoid or minimise the adverse effects on ecological values during the commissioning and operation of the facility.<br>· To prevent the introduction and spread of new or existing weeds, or plant and animal pathogens.<br>· Avoiding clearing of remnant vegetation. Essential activities such as wildfire control at the Facility perimeter and the rehabilitation of disused facility infrastructure may require some minor vegetation cutting.<br>· Exclusion of wildlife from the Facility site with the use of 6 ft-high security fences. | · To avoid or minimise the adverse effects on ecological values during the commissioning and operation of the facility.<br>· To prevent the introduction and spread of new or existing weeds, or plant and animal pathogens.<br>· Avoiding clearing of remnant vegetation. Essential activities such as wildfire control at the Facility perimeter and the rehabilitation of disused facility infrastructure may require some minor vegetation cutting.<br>· Exclusion of wildlife from the Facility site with the use of 6 ft-high security fences. | · To avoid or minimise the adverse effects on ecological values during the commissioning and operation of the facility.<br>· To prevent the introduction and spread of new or existing weeds, or plant and animal pathogens.<br>· Avoiding clearing of remnant vegetation. Essential activities such as wildfire control at the Facility perimeter and the rehabilitation of disused facility infrastructure may require some minor vegetation cutting.<br>· Exclusion of wildlife from the Facility site with the use of 6 ft-high security fences. | · To avoid or minimise the adverse effects on ecological values during the commissioning and operation of the facility.<br>· To prevent the introduction and spread of new or existing weeds, or plant and animal pathogens.<br>· Avoiding clearing of remnant vegetation. Essential activities such as wildfire control at the Facility perimeter and the rehabilitation of disused facility infrastructure may require some minor vegetation cutting.<br>· Exclusion of wildlife from the Facility site with the use of 6 ft-high security fences. |
| **Hazardous Material** | · Training workers on the correct transfer and handling of fuels and chemicals and the response to spills<br>· Providing portable spill containment and cleanup equipment<br>· on site and training in the equipment deployment<br>· Assessing the contents of hazardous materials and petroleum-based products in building systems<br>· Assessing the presence of hazardous | · Training workers on the correct transfer and handling of fuels and chemicals and the response to spills<br>· Providing portable spill containment and cleanup equipment<br>· on site and training in the equipment deployment<br>· Assessing the contents of hazardous materials and petroleum-based products in building systems<br>· Assessing the presence of hazardous | · Using impervious surfaces for refueling areas and other fluid transfer areas<br>· Training workers on the correct transfer and handling of fuels and chemicals and the response to spills<br>· Providing portable spill containment and cleanup equipment<br>· on site and training in the equipment deployment<br>· Assessing the contents of hazardous | · Using impervious surfaces for refueling areas and other fluid transfer areas<br>· Training workers on the correct transfer and handling of fuels and chemicals and the response to spills<br>· Providing portable spill containment and cleanup equipment<br>· on site and training in the equipment deployment<br>· Assessing the contents of hazardous materials and petroleum-based products in |

| Parameter | Crude Oil Pipeline | Product Pipeline | Storage Terminal | Refinery |
|---|---|---|---|---|
| | substances in or on building materials (e.g., polychlorinated biphenyls, asbestos containing flooring or insulation) and decontaminating or properly managing contaminated building materials | substances in or on building materials (e.g., polychlorinated biphenyls, asbestos containing flooring or insulation) and decontaminating or properly managing contaminated building materials | materials and petroleum-based products in building systems<br>· Assessing the presence of hazardous substances in or on building materials (e.g., polychlorinated biphenyls, asbestos containing flooring or insulation) and decontaminating or properly managing contaminated building materials<br>· Storage tanks and components (e.g. roofs and seals) should undergo periodic inspection for corrosion and structural integrity and be subject to regular maintenance and replacement of equipment (e.g. pipes, seals)<br>· Develop a formal spill prevention and control plan that addresses significant scenarios and magnitude of releases | building systems<br>· Assessing the presence of hazardous substances in or on building materials (e.g., polychlorinated biphenyls, asbestos containing flooring or insulation) and decontaminating or properly managing contaminated building materials<br>· Storage tanks and components (e.g. roofs and seals) should undergo periodic inspection for corrosion and structural integrity and be subject to regular maintenance and replacement of equipment (e.g. pipes, seals<br>·<br>· Develop a formal spill prevention and control plan that addresses significant scenarios and magnitude of releases |
| **Waste** | · Monitoring and identifying When significant quantities of hazardous wastes are generated<br>· Tracking of waste generation trends by type and amount of waste generated, preferably by facility<br>· Characterizing waste at the beginning of generation to ensure proper management of the waste, especially hazardous wastes<br>· Keeping manifests or other records that document the amount of waste generated and its destination<br>· Periodic auditing of third party treatment and disposal services Having a comprehensive waste management plan | · Monitoring and identifying When significant quantities of hazardous wastes are generated<br>· Tracking of waste generation trends by type and amount of waste generated, preferably by facility<br>· Characterizing waste at the beginning of generation to ensure proper management of the waste, especially hazardous wastes<br>· Keeping manifests or other records that document the amount of waste generated and its destination<br>· Periodic auditing of third party treatment and disposal services Having a comprehensive waste management plan | · Regular inspections of waste segregation and collection practices<br>· Characterizing waste especially hazardous waste<br>· Keeping records that document the amount of waste generated and its destination<br>· Installing on-site waste treatment or recycling processes<br>· Evaluation of waste production processes and identification of potentially recyclable materials | · Regular inspections of waste segregation and collection practices<br>· Characterizing waste especially hazardous waste<br>· Keeping records that document the amount of waste generated and its destination<br>· Installing on-site waste treatment or recycling processes<br>· Evaluation of waste production processes and identification of potentially recyclable materials |
| **Noise** | · Selecting equipment with lower sound power levels<br>· Installing suitable mufflers on engine exhausts and compressor components<br>· Installing acoustic enclosures for equipment casing radiating noise<br>· Installing acoustic barriers Installing vibration isolation for mechanical equipment<br>· Limiting the hours of operation for specific pieces of equipment or operations, especially mobile sources | · Selecting equipment with lower sound power levels<br>· Installing suitable mufflers on engine exhausts and compressor components<br>· Installing acoustic enclosures for equipment casing radiating noise<br>· Installing acoustic barriers Installing vibration isolation for mechanical equipment<br>· Limiting the hours of operation for specific pieces of equipment or operations, especially mobile sources operating through community areas | · Avoiding or minimizing project transportation through community areas<br>· Siting permanent facilities away from community areas if possible<br>· Installing suitable mufflers on engine exhausts and compressor components<br>· Developing a mechanism to record and respond to complaints<br>· Preventing uncontrolled releases of hazardous materials or uncontrolled reactions that might result in fire or explosion | · Avoiding or minimizing project transportation through community areas<br>· Installing suitable mufflers on engine exhausts and compressor components<br>· Siting permanent facilities away from community areas if possible<br>· Developing a mechanism to record and respond to complaints<br>· Design noise monitoring programs<br>· Preventing uncontrolled releases of hazardous materials or uncontrolled |

| Parameter | Crude Oil Pipeline | Product Pipeline | Storage Terminal | Refinery |
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| | operating through community areas<br>· Re-locating noise sources to less sensitive areas to take advantage of distance and shielding<br>· Siting permanent facilities away from community areas if possible<br>· Taking advantage of the natural topography as a noise buffer during facility design | · Re-locating noise sources to less sensitive areas to take advantage of distance and shielding<br>· Siting permanent facilities away from community areas if possible<br>· Taking advantage of the natural topography as a noise buffer during facility design | · Clearly identifying and marking harmful noise areas and indicate where PPE should be used.<br>· | reactions that might result in fire or explosion<br>· Clearly identifying and marking harmful noise areas and indicate where PPE should be used. |
| **Occupation al, Health and Safety Issues** | · Conducting a spill risk assessment for offshore facilities and support vessels;<br>· Install valves, including subsea shutdown valves, to allow early shutdown or isolation in the event of an emergency;<br>· Ensure adequate corrosion allowance for the lifetime of the facilities and / or installation of corrosion control and prevention systems in all pipelines, process equipment, and tanks;<br>· maintenance programs should include regular pigging to clean the pipeline, and intelligent pigging should also be<br>· considered as required;<br>· Install leak detection systems.<br>· For facilities with potentially significant releases, install an Emergency Shutdown System that initiates automatic shutdown actions to bring the offshore facility to a safe condition;<br>· Adequate personnel training in oil spill/leak prevention, containment and response.<br>· Ensure spill response and containment equipment is deployed or available as necessary for response; | · Conducting a spill risk assessment for offshore facilities and support vessels;<br>· Install valves, including subsea shutdown valves, to allow early shutdown or isolation in the event of an emergency;<br>· Ensure adequate corrosion allowance for the lifetime of the facilities and / or installation of corrosion control and prevention systems in all pipelines, process equipment, and tanks;<br>· maintenance programs should include regular pigging to clean the pipeline, and intelligent pigging should also be<br>· considered as required;<br>· ☐Install leak detection systems.<br>· For facilities with potentially significant releases, install an Emergency Shutdown System that initiates automatic shutdown actions to bring the offshore facility to a safe condition;<br>· Adequate personnel training in oil spill/leak prevention, containment and response.<br>· Ensure spill response and containment equipment is deployed or available as necessary for response; | · Worker training<br>· Provision of appropriate PPEs<br>· Fire Management Plan<br>· Control and management of Hazardous conditions<br>· Restricting access<br>· Emergency Action Plans<br>· Practicing of ergonomics<br>· Medical Testing for workers | · Worker training<br>· Provision of appropriate PPEs<br>· Fire Management Plan<br>· Control and management of Hazardous conditions<br>· Restricting access<br>· Emergency Action Plans<br>· Practicing of ergonomics<br>· Medical Testing for workers |
| **Community Health and Safety** | · Emphasizing safety aspects all actors<br>· Improving driving skills and requiring licensing of drivers<br>· Adopting limits for trip duration and arranging driver rosters to avoid overtiredness<br>· Avoiding dangerous routes and times of day to reduce the risk of accidents<br>· Use of speed control devices (governors) on trucks, and remote monitoring of driver actions | · Emphasizing safety aspects all actors<br>· Improving driving skills and requiring licensing of drivers<br>· Adopting limits for trip duration and arranging driver rosters to avoid overtiredness<br>· Avoiding dangerous routes and times of day to reduce the risk of accidents<br>· Use of speed control devices (governors) on trucks, and remote monitoring of driver actions | · Emphasizing safety aspects all actors<br>· Improving driving skills and requiring licensing of drivers<br>· Adopting limits for trip duration and arranging driver rosters to avoid overtiredness<br>· Avoiding dangerous routes and times of day to reduce the risk of accidents<br>· Use of speed control devices (governors) on trucks, and remote monitoring of driver actions | · Emphasizing safety aspects all actors<br>· Improving driving skills and requiring licensing of drivers<br>· Adopting limits for trip duration and arranging driver rosters to avoid overtiredness<br>· Avoiding dangerous routes and times of day to reduce the risk of accidents<br>· Use of speed control devices (governors) on trucks, and remote monitoring of driver actions |

| Parameter | Crude Oil Pipeline | Product Pipeline | Storage Terminal | Refinery |
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| | • Minimizing pedestrian interaction with construction vehicles<br>• Collaboration with local communities and responsible authorities to improve signage, visibility and overall safety of roads,<br>• Coordination with emergency responders to ensure that appropriate first aid is provided in the event of accidents<br>• Using locally sourced materials, whenever possible, to minimize transport distances. Locating associated facilities such as worker camps close to project sites and arranging<br>• worker bus transport to minimizing external traffic Training health workers in disease treatment<br>• Conducting immunization programs for workers in local<br>• communities to improve health and guard against infection<br>• Providing health services<br>• Providing treatment through standard case management in on-site or community health care facilities. Ensuring ready access to medical treatment, confidentiality and appropriate care, particularly with respect to migrant workers<br>• Promoting collaboration with local authorities to enhance access of workers families and the community to public health services and promote immunization<br>• Prevention of larval and adult propagation through sanitary improvements and elimination of breeding habitats close to human settlements<br>• Elimination of unusable impounded water<br>• Increase in water velocity in natural and artificial channels<br>• Considering the application of residual insecticide to dormitory walls<br>• Implementation of integrated vector control programs | • Minimizing pedestrian interaction with construction vehicles<br>• Collaboration with local communities and responsible authorities to improve signage, visibility and overall safety of roads, □□Coordination with emergency responders to ensure that appropriate first aid is provided in the event of accidents<br>• Using locally sourced materials, whenever possible, to minimize transport distances. Locating associated facilities such as worker camps close to project sites and arranging<br>• worker bus transport to minimizing external traffic Training health workers in disease treatment<br>• Conducting immunization programs for workers in local<br>• communities to improve health and guard against infection<br>• Providing health services<br>• Providing treatment through standard case management in on-site or community health care facilities. 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Locating associated facilities such as worker camps close to project sites and arranging worker bus transport to minimizing external traffic Training health workers in disease treatment<br>• Conducting immunization programs for workers in local<br>• communities to improve health and guard against infection<br>• Providing health services<br>• Providing treatment through standard case management in on-site or community health care facilities. Ensuring ready access to medical treatment, confidentiality and appropriate care, particularly with respect to migrant workers<br>• Promoting collaboration with local authorities to enhance access of workers families and the community to public health services and promote immunization<br>• Prevention of larval and adult propagation through sanitary improvements and elimination of breeding habitats close to human settlements<br>• Elimination of unusable impounded water<br>• □□Increase in water velocity in natural and artificial channels<br>• Considering the application of residual insecticide to dormitory walls<br>• □□Implementation of integrated vector control programs<br>• Promoting use of repellents, clothing, netting, and other barriers to prevent insect bites<br>• Use of chemoprophylaxis drugs by non-immune workers and collaborating with public health officials to help eradicate disease reservoirs | • Minimizing pedestrian interaction with construction vehicles<br>• Collaboration with local communities and responsible authorities to improve signage, visibility and overall safety of roads, □□Coordination with emergency responders to ensure that appropriate first aid is provided in the event of accidents<br>• Using locally sourced materials, whenever possible, to minimize transport distances. Locating associated facilities such as worker camps close to project sites and arranging<br>• worker bus transport to minimizing external traffic Training health workers in disease treatment<br>• Conducting immunization programs for workers in local<br>• communities to improve health and guard against infection<br>• Providing health services<br>• Providing treatment through standard case management in on-site or community health care facilities. Ensuring ready access to medical treatment, confidentiality and appropriate care, particularly with respect to migrant workers<br>• Promoting collaboration with local authorities to enhance access of workers families and the community to public health services and promote immunization<br>• Prevention of larval and adult propagation through sanitary improvements and elimination of breeding habitats close to human settlements<br>• Elimination of unusable impounded water<br>• Increase in water velocity in natural and artificial channels<br>• Considering the application of residual insecticide to dormitory walls<br>• Implementation of integrated vector control programs<br>• Promoting use of repellents, clothing, netting, and other barriers to prevent insect bites<br>• Use of chemoprophylaxis drugs by non-immune workers and collaborating with public health officials to help eradicate |

| Parameter | Crude Oil Pipeline | Product Pipeline | Storage Terminal | Refinery |
|---|---|---|---|---|
| | · Promoting use of repellents, clothing, netting, and other barriers to prevent insect bites<br>· Use of chemoprophylaxis drugs by non-immune workers and collaborating with public health officials to help eradicate disease reservoirs<br>· Monitoring and treatment of circulating and migrating populations to prevent disease reservoir spread<br>· Collaboration and exchange of in-kind services with other control programs in the project area to maximize beneficial effects<br>· Educating project personnel and area residents on risks,<br>· prevention, and available treatment | disease reservoirs<br>· Monitoring and treatment of circulating and migrating populations to prevent disease reservoir spread<br>· Collaboration and exchange of in-kind services with other control programs in the project area to maximize beneficial effects<br>· Educating project personnel and area residents on risks,<br>· prevention, and available treatment | · Monitoring and treatment of circulating and migrating populations to prevent disease reservoir spread<br>· Collaboration and exchange of in-kind services with other control programs in the project area to maximize beneficial effects Educating project personnel and area residents on risks,<br>· prevention, and available treatment | disease reservoirs<br>· Monitoring and treatment of circulating and migrating populations to prevent disease reservoir spread<br>· Collaboration and exchange of in-kind services with other control programs in the project area to maximize beneficial effects<br>· Educating project personnel and area residents on risks,<br>· prevention, and available treatment |

*Source: PwC Consortium Analysis*

## 10.4. Gas Monetisation Options Environmental and Social Impacts

Based on the discussion of potential gas monetisation options, we present in the table below selected potential environmental impacts and mitigation measure the Government can consider.

*Table 10.4: Gas options environmental and social impacts*

| Parameter | LNG | Ammonia Plant | CCGT Power Plant | Gas Pipeline | Methanol Plant |
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| **Air** | · Air emissions (continuous or non-continuous) from LNG facilities include combustion sources for power and heat generation (e.g. for dehydration and liquefaction activities at LNG liquefaction terminals, and regasification activities at LNG receiving terminals)<br>· Nitrogen oxides (NOX), carbon monoxide (CO), carbon dioxide ($CO_2$), and, in case of sour gases, sulfur dioxide ($SO_2$) may result from NLG plant activities<br>· Exhaust gas emissions produced by the combustion liquid hydrocarbons in turbines, boilers, compressors, pumps and other engines for power and heat generation, can be the most significant source of air emissions from LNG facilities.<br>· After LNG liquefaction, stored LNG emits methane gas vapor, known as 'boil off gas' (BOG)<br>· Fugitive emissions which may be associated with cold vents, leaking pipes and tubing, valves, connections, flanges, packings, open-ended lines, pump seals, compressor seals, pressure relief valves, and general loading and unloading operations. | · Emissions from ammonia plants consist mainly of carbon dioxide ($CO_2$), ammonia ($NH_3$), and carbon monoxide (CO) and Hydrogen sulfide ($H_2S$) depending on the fuel used. These gases increase in GHGs concentration in the atmosphere | · The combustion of natural gas in the plant will produce large amounts of NOx per year.<br>· The presence of NOx in the atmosphere in large amounts is harmful to human, animals and plants | · Dust during construction/laying of pipes<br>· Volatile Organic Compound Release<br>· Methane release into the environment | · Fugitive emissions in natural gas processing facilities associated with leaks in tubing; valves; connections; flanges; packings; open-ended lines; floating roof storage tank, pump, and compressor seals; gas conveyance systems, pressure relief valves, tanks or open pits / containments, and loading and unloading operations of hydrocarbons<br>· Significant amounts of carbon dioxide ($CO_2$) may be emitted from Syn-gas manufacturing, mainly from $CO_2$ washing, and from all combustion processes (e.g., electric power production and byproduct incineration).<br>· Exhaust gas emissions produced by the combustion of gas or other hydrocarbon fuels in turbines, boilers, compressors, pumps, and other engines for power and heat generation are a significant source of air emissions from natural gas processing facilities.<br>· Incineration of oxygenated byproducts at GTL production facilities also generates $CO_2$ and nitrogen oxides (NOX) emissions.<br>· Unreacted raw materials and by-product combustible gases are also disposed of through venting and flaring |
| **Water** | · Leads to generation of non-hazardous and hazardous | · During normal operations, plant discharges may include releases of | · Wastewater, if not incorporated with the necessary precautions has | · Leaks into water bodies<br>· Water acidification | · May contain dissolved hydrocarbons, oxygenated |

| Parameter | LNG | Ammonia Plant | CCGT Power Plant | Gas Pipeline | Methanol Plant |
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| | wastes that can pollute water such as general office and packaging wastes, waste oils, oil contaminated rags, hydraulic fluids, used batteries, empty paint cans, waste chemicals and used chemical containers, used filters, spent sweetening and dehydration media (e.g. molecular sieves) and oily sludge from oil water separators, spent amine from acid gas removal units, scrap metals, and medical waste, among others. | process condensates or scrubbing effluents of waste gases containing ammonia and other byproducts.<br>· Process condensates may contain ammonia, methanol, and amines (e.g., methylamines, dimethylamines and trimethylamines).<br>· In partial oxidation, soot and ash removal may impact water discharges if not handled adequately condensation between shift reactors and absorption of carbon dioxide, and from carbon | an adverse impacts to human health, safety, or the environment.<br>· Utility operations such as cooling towers and demineralization systems may result in high rates of water consumption<br>· High potential release of high temperature water containing high dissolved solids, residues of biocides, residues of other cooling system anti-fouling agents, etc. which is harmful to the receiving environment. | · Impact on water biology | compounds, and other contaminants<br>· Storm water may become contaminated as a result of spills of process liquids<br>· Cooling water may necessitate high rates of water consumption, as well as the potential release of high temperature water, residues of biocides, and residues of other cooling system anti- fouling agents |
| **Soil** | · Leaks and spills into the soil<br>· The potential risks to human health and ecology<br>· The economic liability that it may pose to the polluter/business owners<br>· Impact on soil biology<br>· Soil compaction | · Contamination of soil due to releases of materials, wastes and/or naturally occurring substances that contain traces of ammonia.<br>· Contaminated lands may involve surficial soils or subsurface soils that, through leaching and transport, may affect groundwater, surface water and adjacent sites.<br>· Where subsurface contaminant sources include volatile substances, soil vapor and carbon condensation between shift reactors and absorption of carbon dioxide | · The plant will use, store, or handle quantity of materials which may be hazardous /materials that represent a risk to human health, property, or the environment due to their physical or chemical characteristic.<br>· The potential risks to human health and ecology (e.g. risk of cancer or other human health effects, loss of ecology) | · Soil structure disturbance and compaction<br>· Leaks and spills into the soil<br>· The potential risks to human health and ecology<br>· The economic liability that it may pose to the polluter/business owners<br>· Soil chemical properties<br>· Impact on soil biology | · Leaks and spills into the soil<br>· The potential risks to human health and ecology<br>· The economic liability that it may pose to the polluter/business owners<br>· Impact on soil biology<br>· Soil compaction |
| **Flora and Fauna** | · Dredging, disposal of dredge spoil, construction of piers, wharves, breakwaters, and other water-side structures, and erosion may lead to short and long term impacts on aquatic and shoreline habitats<br>· Physical removal or covering of sea floor, shore, or land-side habitat<br>· Changes to water quality from sediment suspension or discharges of storm water and wastewater<br>· Discharge of ballast water and | · Cutting down of vegetation<br>· Potential risk of fire upon ignited leakages<br>· Cut off animal routes when the pipes are wall-secured<br>· Loss of breeding grounds<br>· Loss of habitats | · Cutting down of vegetation<br>· Potential risk of fire upon ignited leakages<br>· Cut off animal routes when the pipes are wall-secured<br>· Loss of breeding grounds<br>· Loss of habitats | · Cutting down of vegetation<br>· Potential risk of fire upon ignited leakages<br>· Cut off animal routes when the pipes are wall-secured<br>· Loss of breeding grounds<br>· Loss of habitats<br>· Risk of fires | · Cutting down of vegetation<br>· Potential risk of fire upon ignited leakages<br>· Cut off animal routes when the pipes are wall-secured<br>· Loss of breeding grounds<br>· Loss of habitats |

| Parameter | LNG | Ammonia Plant | CCGT Power Plant | Gas Pipeline | Methanol Plant |
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| | sediment from ships during LNG terminal loading operations may result in the introduction of invasive aquatic species | | | | |
| **Hazardous Material** | · Storage, transfer, and transport of LNG may result in leaks<br>· Accidental release from tanks, pipes, hoses, and pumps at land<br>· Pose a risk of fire and explosion due to the flammable characteristics of its boil-off gas. | · Pose the potential for release of petroleum based products, such as lubricants, hydraulic fluids, or fuels during their storage, transfer, or use in equipment. | · Pose the potential for release of petroleum based products, such as lubricants, hydraulic fluids, or fuels during their storage, transfer, or use in equipment. | · Pose the potential for release of petroleum based products, such as lubricants, hydraulic fluids, or fuels during their storage, transfer, or use in equipment. | · Pose the potential for release of petroleum based products, such as lubricants, hydraulic fluids, or fuels during their storage, transfer, or use in equipment. |
| **Waste** | · The use of water for process cooling at LNG liquefaction facilities and for re-vaporization heating at LNG receiving terminals may result in significant water use and discharge streams<br>· Other waste waters routinely generated at LNG facilities include process wastewater drainage, sewage waters, tank bottom water (e.g. from condensation in LNG storage tanks), fire water, equipment and vehicle wash waters, and general oily water. | · Spent catalysts after their replacement in scheduled turnarounds of gas desulphurization, ammonia plants, and nitric acid plants are the most common hazardous wastes produced by these facilities which are harmful to the receiving environment. | · Mismanagement of waste collection causes harm to human health and safety, and the environment at large. | · Compromised aesthetic value from pipe cuttings and spoils<br>· Earth overburden from the trench digging | · Non-hazardous industrial wastes consist mainly of exhausted molecular sieves from the air separation unit as well as domestic wastes may emanate from the processing plant. Other non-hazardous wastes may include office and packaging wastes, construction rubble, and scrap metal<br>· Hazardous wastes that include bio-sludge; spent catalysts; spent oil, solvents, and filters (e.g., activated carbon filters and oily sludge from oil water separators); used containers and oily rags; mineral spirits; used sweetening; spent amines for $CO_2$ removal; and laboratory may emanate from the plant<br>· Natural gas processing facilities use and manufacture significant amounts of hazardous materials, including raw materials, intermediate / final products and by-products |
| **Noise** | · Noise pollution emanates from pumps, compressors, generators and drivers, compressor suction / discharge, recycle piping, air dryers, heaters, air coolers at | · Noise beyond the property boundary of the facilities<br>· Potential for exposer to workers to noise greater than 85 dB(A) for a duration of more than 8 hours per day without hearing protection | · Noise beyond the property boundary<br>· Potential for exposer to workers to noise greater than 85 dB(A) for a duration of more than 8 hours per day without hearing protection | · Occupational impact to the workers<br>· Acoustic impact to wildlife | · Noise from large rotating machines (e.g. compressors, turbines, pumps, electric motors, air coolers, and fired heaters)<br>· During emergency depressurization, high noise levels |

| Parameter | LNG | Ammonia Plant | CCGT Power Plant | Gas Pipeline | Methanol Plant |
|---|---|---|---|---|---|
| | liquefaction facilities, vaporizers used during regasification, and general loading / unloading operations of LNG carriers / vessels. | | | | can be generated due to release of high-pressure gases to flare and /or steam release into the atmosphere |
| **Occupational, Health and Safety Issues** | · Roll over<br>· Fires and Explosions<br>· Chemical Hazards<br>· Confined spaces<br>· Contact with cold surfaces | · Fires and explosions<br>· Chemical hazards<br>· Confined spaces<br>· Contact with cold surfaces | · Fires and explosions<br>· Chemical hazards<br>· Confined spaces<br>· Contact with cold surfaces<br>· Moving machinery<br>· Falls<br>· Falling objects | · Accidental fires<br>· Release of hazardous compounds into the soil and water in case of leakages<br>· Fugitive dust during construction<br>· Moving machinery<br>· Falls<br>· Falling objects | · Leaks of oxygen-enriched from air separation units can create a fire risk.<br>· Oxygen-enriched atmospheres may potentially result in the saturation of materials, hair, and clothing with oxygen, which may burn violently if ignited.<br>· The potential releases and accumulation of nitrogen gas into work areas can result asphyxiating conditions due to the displacement of oxygen by these gases.<br>· Chemical exposures in natural gas processing facilities mainly related to carbon monoxide and methanol releases causes potential inhalation exposures to chemicals emissions during routine plant operation<br>· Fire and explosion hazards generated by process operations include the accidental release of syn-gas (containing carbon monoxide and hydrogen), oxygen, and methanol. High pressure syn-gas releases may cause "jet fires" or give rise to a vapor cloud explosion (vce), |
| **Community Health and Safety** | · Security<br>· General site hazards<br>· Diseases<br>· Traffic safety<br>· Fires and explosions | · Security<br>· General site hazards<br>· Diseases<br>· Traffic safety<br>· Fires and explosions | · Security<br>· General site hazards<br>· Diseases<br>· Traffic safety<br>· Fires and explosions | · Security<br>· General site hazards<br>· Diseases<br>· Traffic safety<br>· Fires and explosions | · Security<br>· General site hazards<br>· Diseases<br>· Traffic safety<br>· Fires and explosions |

*Source: PwC Consortium Analysis*

*Table 10.5: Gas options environmental and social impacts mitigation measures*

| Parameter | LNG | Ammonia Plant | CCGT Power Plant | Gas Pipeline | Methanol Plant |
|---|---|---|---|---|---|
| **Air** | · All reasonable attempts should be made to maximize energy efficiency and design facilities to minimize energy use. The overall objective should be to reduce air emissions and evaluate cost-effective options for reducing emissions that are technically feasible.<br>· Air emission specifications should be considered during all equipment selection and procurement.<br>· Flaring or venting should be used only in emergency or plant upset conditions. Continuous venting or flaring of boil-off gas under normal operations is not considered good industry practice and should be avoided<br>· Boil off gas (BOG) should be collected using an appropriate vapor recovery system (e.g. compressor systems).<br>· Methods for controlling and reducing fugitive emissions should be considered and implemented in the design, operation, and maintenance of facilities. | · Use synthesis $NH_3$ purge gas treatment to recover $NH_3$ and $H_2$ before combustion of the remainder in the primary reformer;<br>· Increase the residence time for off-gas in the high-temperature zone of the primary reformer;<br>· Ammonia emissions from relief valves or pressure control devices from vessels or storages should be collected and sent to a flare or to wet scrubber;<br>· Install leak detection methods to detect fugitive emissions of ammonia from process and storage;<br>· Implement maintenance programs, particularly in stuffing boxes on valve stems and seals on relief valves, to reduce or eliminate releases. | · Ensure that a sufficient air supply is provided to the oxidizer and absorber;<br>· Prevent high temperatures in the cooler-condenser and absorber;<br>· Develop a maintenance program to prevent operation with faulty equipment such as compressors or pumps that lead to lower pressures and leaks, and decrease plant efficiency;<br>· Reduce NOX emissions by increasing the efficiency of the existing process absorption tower or incorporating an additional absorption tower;<br>· Apply a catalytic reduction process to treat tail gases from the absorption tower;<br>· Install active molecular sieves to catalytically oxidize NO to $NO_2$ and selectively adsorb $NO_2$, returning the thermally stripped $NO_2$ to the absorber;<br>· Install wet scrubbers with an aqueous solution of alkali hydroxides or carbonates, ammonia, urea, potassium permanganate, or caustic chemicals (e.g. caustic scrubbers with sodium hydroxide, sodium carbonate, or other strong bases), recovering NO and $NO_2$ as nitrate or nitrate salts. | · Review air use reduction opportunities, such training of staff<br>· Monitor pressure losses in filters and replace as appropriate<br>· Use adequately sized distribution pipework designed to minimize pressure losses<br>· Do not mix high volume low pressure and low volume high pressure loads. Decentralize low volume high-pressure applications or provide dedicated<br>· Examine each true user of compressed air to identify the air volume needed and the pressure at which this should be delivered.<br>· Maximize energy Efficiency and design facilities for lowest energy use to reduce air emissions and evaluate cost effective options for reducing emissions that are technically feasible.<br>· Collection of vapors through air extractors and subsequent treatment of gas stream by removing VOCs with control devices such as condensers or activated carbon absorption;<br>· Collection of vapors through air extractors and subsequent treatment with destructive control devices such as: Catalytic Incinerators, Thermal Incinerators and enclosed oxidizing Flares set to convert VOCs into $CO_2$ and $H_2O$ by way of direct combustion | · Regularly monitor fugitive emissions from pipes, valves, seals, tanks, and other infrastructure components with vapor detection equipment, and maintenance or replacement of components as needed in a prioritized manner<br>· Selecting and designing storage tanks in accordance with internationally accepted standards to minimize storage and working losses considering, for example, storage capacity and the vapor pressure of materials being stored<br>· Use supply and return systems, vapor recovery hoses, and vapor-tight trucks / railcars / vessels during loading and unloading of transport vehicles<br>· Where vapor emissions contribute or result in ambient air quality levels in excess of health based standards, install secondary emissions controls, such as vapor condensing and recovery units, catalytic oxidizers, vapor combustion units, or gas adsorption media.<br>· Use bottom-loading truck / rail car filling systems; and<br>· Emissions related to the operation of power sources should be minimized through the adoption of a combined strategy which includes a reduction in energy demand, use of cleaner fuels, and application of emissions controls where required.<br>· Excess gas should not be vented but instead sent to an efficient |
| **Water** | · Water conservation opportunities should be considered for LNG facility cooling systems (e.g. air cooled heat exchangers in place of water cooled heat exchangers | · Condensates should be steam-stripped to reduce the ammonia content, and re-used as boiler make-up water after an ion exchange treatment or sent to a wastewater treatment plant for | · Steam-inject the NOX compressor to avoid any liquid effluent;<br>· Understand the quality, quantity, frequency and sources of liquid effluents in its installations. This includes knowledge about the | · There should be a spill prevention and control plan<br>· Where appropriate, spill control and response plans should be developed in coordination with the relevant local regulatory agencies | · Process wastewater and other wastewaters, which may be contain dissolved hydrocarbons, oxygenated compounds, and other contaminants, should be treated at the onsite wastewater treatment |

| Parameter | LNG | Ammonia Plant | CCGT Power Plant | Gas Pipeline | Methanol Plant |
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| | and opportunities for the integration of cold water discharges with other proximate industrial or power plant facilities). | treatment with other ammonical streams. Steam-tripper emissions may require additional ammonical emissions controls;<br>· Ammonia absorbed from purge and flash gases should be recovered in a closed loop to avoid the occurrence of aqueous ammonia emissions;<br>· Soot from gasification in partial oxidation processes should be recovered and recycled to the process. | locations, routes and integrity of internal drainage systems and discharge points<br>· Plan and implement the segregation of liquid effluents principally along industrial, utility, sanitary, and storm water categories, in order to limit the volume of water requiring specialized treatment.<br>· Identify opportunities to prevent or reduce wastewater pollution through such measures as recycle/reuse within their facility, input substitution, or process modification (e.g. change of technology or operating conditions/modes)<br>· Water use efficiency to reduce the amount of wastewater generation<br>· Process modification, including waste minimization, and reducing the use of hazardous materials to reduce the load of pollutants requiring treatment<br>· Application of wastewater treatment techniques to further reduce the load of contaminants prior to discharge | | unit (WWTU).<br>· Prevention and control of accidental releases of liquids through inspections and maintenance of storage and conveyance systems, including stuffing boxes on pumps and valves and other potential leakage points, as well as<br>· the implementation of spill response plans;<br>· Provision of sufficient process fluids let-down capacity to maximize recovery into the process and to avoid massive<br>· process liquids discharge into the oily water drain system<br>· Design and construction of wastewater and hazardous materials storage containment basins with impervious surfaces to prevent infiltration of contaminated water into soil and groundwater<br>· Natural gas processing facilities should provide secondary containment where liquids are handled, segregate contaminated and non-contaminated storm water, implement spill control plans, and route storm water from process areas into the wastewater treatment unit.<br>· Use of heat recovery methods (also energy efficiency improvements) or other cooling methods to reduce the temperature of heated water prior to discharge to ensure the discharge water temperature does not result in an increase greater than 3°C of ambient temperature at the edge of a scientifically established mixing zone that takes into account ambient water quality, receiving water use, assimilative capacity , etc. |
| **Soil** | · Controlling the release of | · Contamination of land should be | · Identification of the location of | · Regular monitoring and | · Controlling the release of |

| Parameter | LNG | Ammonia Plant | CCGT Power Plant | Gas Pipeline | Methanol Plant |
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| | hazardous materials, hazardous wastes, or oil to the environment<br>· contaminated soil identification and correction to avoid further releases and associated adverse impacts<br>· Contaminated soils should be managed to avoid the risk to human health and ecological receptors. The preferred strategy for soil is to reduce the level of contamination at the site while preventing the human exposure to contamination. | avoided by preventing or controlling the release of materials and hazardous wastes containing ammonia to the environment. Uncontrolled release of substances with ammonia traces should be identified and corrected to avoid further releases and associated adverse impacts.<br>· Contaminated lands should be managed to avoid the risk to human health and ecological receptors. | suspected highest level of contamination through a combination of visual and historical operational information;<br>· Sampling and testing of the contaminated media (soils or water) according to established technical methods applicable to suspected type of contaminant.<br>· Evaluation of the analytical results against the local and national contaminated sites regulations. In the absence of such regulations or environmental standards, other sources of risk-based standards or guidelines should be consulted to obtain comprehensive criteria for screening soil concentrations of pollutants.<br>· Verification of the potential human and/or ecological receptors and exposure pathways relevant to the site in question | installation of leak detectors<br>· Controlling the release of hazardous materials, hazardous wastes, or oil to the environment | hazardous materials, hazardous wastes, or oil to the environment<br>· contaminated soil identification and correction to avoid further releases and associated adverse impacts<br>· Contaminated soils should be managed to avoid the risk to human health and ecological receptors. The preferred strategy for soil is to reduce the level of contamination at the site while preventing the human exposure to contamination. |
| **Flora and Fauna** | · To avoid or minimise the adverse effects on ecological values during the commissioning and operation of the facility.<br>· To prevent the introduction and spread of new or existing weeds, or plant and animal pathogens.<br>· Avoiding clearing of remnant vegetation. Essential activities such as wildfire control at the Facility perimeter and the rehabilitation of disused facility infrastructure may require some minor vegetation cutting.<br>· Exclusion of wildlife from the Facility site with the use of 6 ft-high security fences. | · To avoid or minimise the adverse effects on ecological values during the commissioning and operation of the facility.<br>· To prevent the introduction and spread of new or existing weeds, or plant and animal pathogens.<br>· Avoiding clearing of remnant vegetation. Essential activities such as wildfire control at the Facility perimeter and the rehabilitation of disused facility infrastructure may require some minor vegetation cutting.<br>· Exclusion of wildlife from the Facility site with the use of 6 ft-high security fences. | · To avoid or minimise the adverse effects on ecological values during the commissioning and operation of the facility.<br>· To prevent the introduction and spread of new or existing weeds, or plant and animal pathogens.<br>· Avoiding clearing of remnant vegetation. Essential activities such as wildfire control at the Facility perimeter and the rehabilitation of disused facility infrastructure may require some minor vegetation cutting.<br>· Exclusion of wildlife from the Facility site with the use of 6 ft-high security fences. | · To avoid or minimise the adverse effects on ecological values during the commissioning and operation of the facility.<br>· To prevent the introduction and spread of new or existing weeds, or plant and animal pathogens.<br>· Avoiding clearing of remnant vegetation. Essential activities such as wildfire control at the Facility perimeter and the rehabilitation of disused facility infrastructure may require some minor vegetation cutting.<br>· Exclusion of wildlife from the Facility site with the use of 6 ft-high security fences. | · To avoid or minimise the adverse effects on ecological values during the commissioning and operation of the facility.<br>· To prevent the introduction and spread of new or existing weeds, or plant and animal pathogens.<br>· Avoiding clearing of remnant vegetation. Essential activities such as wildfire control at the Facility perimeter and the rehabilitation of disused facility infrastructure may require some minor vegetation cutting.<br>· Exclusion of wildlife from the Facility site with the use of 6 ft-high security fences. |
| **Hazardous Material** | · LNG storage tanks and components (e.g. pipes, valves, and pumps) should meet international standards for | · Using impervious surfaces for refueling areas and other fluid transfer areas<br>· Training workers on the correct | · Using impervious surfaces for refueling areas and other fluid transfer areas<br>· Training workers on the correct | · Training workers on the correct transfer and handling of fuels and chemicals and the response to spills | · Using impervious surfaces for refueling areas and other fluid transfer areas<br>· Training workers on the correct |

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| | structural design integrity and operational performance to avoid catastrophic failures and to prevent fires and explosions during normal operations and during exposure to natural hazards.<br>· Storage tanks and components (e.g. roofs and seals) should undergo periodic inspection for corrosion and structural integrity and be subject to regular maintenance and replacement of equipment (e.g. pipes, seals<br>· Develop a formal spill prevention and control plan that addresses significant scenarios and magnitude of releases<br>· Spill control response plans should be developed in coordination with the relevant local regulatory agencies<br>· Monitor LNG storage tanks for pressure, density, and temperature all along the liquid column;<br>· Consider installation of a system to recirculate the LNG in within the tank;<br>· Install pressure safety valves for tanks designed to<br>· accommodate roll over conditions;<br>· Install multiple loading points at different tank levels to allow for the distribution of LNG with different densities within the tank to prevent stratification. | transfer and handling of fuels and chemicals and the response to spills<br>· Providing portable spill containment and cleanup equipment<br>· on site and training in the equipment deployment<br>· Assessing the contents of hazardous materials and petroleum-based products in building systems<br>· Assessing the presence of hazardous substances in or on building materials (e.g., polychlorinated biphenyls, asbestos containing flooring or insulation) and decontaminating or properly managing contaminated building materials | transfer and handling of fuels and chemicals and the response to spills<br>· Providing portable spill containment and cleanup equipment<br>· on site and training in the equipment deployment<br>· Assessing the contents of hazardous materials and petroleum-based products in building systems<br>· Assessing the presence of hazardous substances in or on building materials (e.g., polychlorinated biphenyls, asbestos containing flooring or insulation) and decontaminating or properly managing contaminated building materials<br>· Storage tanks and components (e.g. roofs and seals) should undergo periodic inspection for corrosion and structural integrity and be subject to regular maintenance and replacement of equipment (e.g. pipes, seals<br>· Develop a formal spill prevention and control plan that addresses significant scenarios and magnitude of releases | · Providing portable spill containment and cleanup equipment<br>· on site and training in the equipment deployment<br>· Assessing the contents of hazardous materials and petroleum-based products in building systems<br>· Assessing the presence of hazardous substances in or on building materials (e.g., polychlorinated biphenyls, asbestos containing flooring or insulation) and decontaminating or properly managing contaminated building materials | transfer and handling of fuels and chemicals and the response to spills<br>· Providing portable spill containment and cleanup equipment<br>· on site and training in the equipment deployment<br>· Assessing the contents of hazardous materials and petroleum-based products in building systems<br>· Assessing the presence of hazardous substances in or on building materials (e.g., polychlorinated biphenyls, asbestos containing flooring or insulation) and decontaminating or properly managing contaminated building materials |
| **Waste** | · Waste materials should be segregated into non-hazardous and hazardous wastes and considered for re-use / recycling prior to disposal<br>· A waste management plan | · Proper on-site management, including submerging pyrophoric spent catalysts in water during temporary storage and transport until they can reach the final point of treatment to avoid uncontrolled | · Establishing waste management priorities at the outset of activities based on an understanding of potential Environmental, Health, and Safety (EHS) risks and impacts and considering waste generation | · Monitoring and identifying when significant quantities of hazardous wastes are generated.<br>· Having a comprehensive waste management plan | · Reducing inventories of hazardous materials through inventory management and process changes to greatly reduce or eliminate the potential off-site consequences of a release |

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| | should be developed that contains a waste tracking mechanism from the originating location to the final waste reception location.<br>· Storage, handling and disposal of hazardous and nonhazardous waste should be conducted in a way consistent with good EHS practice for waste management | exothermic reactions;<br>· Return to the manufacturer for regeneration or recovery;<br>· Off-site management by specialized companies that can recover the heavy or precious metals through recovery and recycling processes whenever possible, or who can otherwise manage spent catalysts or their non-recoverable materials according to hazardous and non-hazardous waste management recommendations | and its consequences<br>· Establishing a waste management hierarchy that considers prevention, reduction, reuse, recovery, recycling, removal and finally disposal of wastes.<br>· Avoiding or minimizing the generation waste materials, as far as practicable<br>· Where waste generation cannot be avoided but has been minimized, recovering and reusing waste; waste cannot be recovered or reused, treating, destroying, and disposing of it in an environmentally sound manner is commended | | · Modifying process or storage conditions to reduce the potential consequences of an accidental off-site release prevention strategies, the total amount of waste may be significantly reduced through the implementation of recycling plans |
| **Noise** | · Vegetation, such as trees, and walls can reduce noise levels.<br>· Installation of acoustic insulating barriers can be implemented, where necessary.<br>· Planning activities in consultation with local communities so that activities with the greatest potential to generate noise are planned during periods of the day that will result in least disturbance<br>· Avoiding or minimizing project transportation through community areas | · Selecting equipment with lower sound power levels<br>· Installing silencers for fans<br>· Installing suitable mufflers on engine exhausts and compressor components<br>· Installing acoustic enclosures for equipment casing radiating noise<br>· Improving the acoustic performance of constructed buildings, apply sound insulation<br>· Installing acoustic barriers without gaps and with a continuous minimum surface density of 10 kg/m in order to minimize the transmission of sound through the barrier. Barriers should be located as close to the source or to the receptor location to be effective<br>· Installing vibration isolation for mechanical equipment<br>· Limiting the hours of operation for specific pieces of equipment or operations, especially mobile sources operating through community areas<br>· Re-locating noise sources to less sensitive areas to take advantage of distance and shielding<br>· Siting permanent facilities away from community areas if possible | · Selecting equipment with lower sound power levels<br>· Installing silencers for fans<br>· Installing suitable mufflers on engine exhausts and compressor components<br>· Installing acoustic enclosures for equipment casing radiating noise<br>· Improving the acoustic performance of constructed buildings, apply sound insulation<br>· Installing acoustic barriers without gaps and with a continuous minimum surface density of 10 kg/m in order to minimize the transmission of sound through the barrier. Barriers should be located as close to the source or to the receptor location to be effective<br>· Installing vibration isolation for mechanical equipment<br>· Limiting the hours of operation for specific pieces of equipment or operations, especially mobile sources operating through community areas<br>· Re-locating noise sources to less sensitive areas to take advantage of distance and shielding<br>· Siting permanent facilities away from community areas if possible | · Selecting equipment with lower sound power levels<br>· Installing suitable mufflers on engine exhausts and compressor components<br>· Installing acoustic enclosures for equipment casing radiating noise<br>· Installing acoustic barriers Installing vibration isolation for mechanical equipment<br>· Limiting the hours of operation for specific pieces of equipment or operations, especially mobile sources operating through community areas<br>· Re-locating noise sources to less sensitive areas to take advantage of distance and shielding<br>· Siting permanent facilities away from community areas if possible<br>· Taking advantage of the natural topography as a noise buffer during facility design | · Noise monitoring programs should be designed and conducted by trained specialists.<br>· Noise impacts should not exceed the levels recommended, or result in a maximum increase in background levels of 3 dB at the nearest receptor location off-site |

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| | | · Taking advantage of the natural topography as a noise buffer during facility design<br>· Reducing project traffic routing through community areas wherever possible<br>· Planning flight routes, timing and altitude for aircraft (airplane and helicopter) flying over community areas<br>· Developing a mechanism to record and respond to complaints | · Taking advantage of the natural topography as a noise buffer during facility design<br>· Reducing project traffic routing through community areas wherever possible<br>· Planning flight routes, timing and altitude for aircraft (airplane and helicopter) flying over community areas<br>· Developing a mechanism to record and respond to complaints | | |
| **Occupational, Health and Safety Issues** | · Occupational health and safety issues should be considered as part of a comprehensive hazard or risk assessment, including, for example, a hazard identification study [HAZID], hazard and operability study [HAZOP], or other risk assessment studies.<br>· The results from the studies should be used for health and safety management planning, in the design of the facility and safe working systems, and in the preparation and communication of safe working procedures.<br>· Facilities should be designed to eliminate or reduce the potential for injury or risk of accident and should take into account prevailing environmental conditions at the site location including the potential for extreme natural hazards such as earthquakes or hurricanes.<br>· Health and safety management planning should demonstrate: that a systematic and structured approach to managing health and safety will be adopted and that controls are in place to reduce risks to the lowest practicable | · Worker training<br>· Provision of appropriate PPEs<br>· Fire Management Plan<br>· Control and management of Hazardous conditions<br>· Restricting access<br>· Emergency Action Plans<br>· Practicing of ergonomics<br>· Medical Testing for workers | · Facility -specific occupational health and safety hazards should be identified based on job safety analysis or comprehensive hazard or risk assessment using established methodologies such as a hazard identification study [HAZID], hazard and operability study [HAZOP], or a scenario-based risk assessment [QRA].<br>· As a general approach, health and safety management planning should include the adoption of a systematic and structured approach for prevention and control of physical, chemical, and biological health and safety hazards<br>· Installation of an automatic Emergency Shutdown System that can detect and warn of the uncontrolled release of oxygen (including the presence of oxygen-enriched atmospheres in working areas) and initiate shutdown actions thus minimizing the duration of releases, and elimination of potential ignition sources<br>· Protection measures include worker training, work permit systems, use of personal protective equipment (PPE), and toxic gas detection systems with alarms.<br>· Avoiding potential sources of | · Conducting a leak risk assessment for offshore facilities and support vessels;<br>· Install valves, including subsea shutdown valves, to allow early shutdown or isolation in the event of an emergency;<br>· Ensure adequate corrosion allowance for the lifetime of the facilities and / or installation of corrosion control and prevention systems in all pipelines, process equipment, and tanks;<br>· maintenance programs should include regular pigging to clean the pipeline, and intelligent pigging should also be<br>· considered as required;<br>· Install leak detection systems.<br>· For facilities with potentially significant releases, install an Emergency Shutdown System that initiates automatic shutdown actions to bring the offshore facility to a safe condition;<br>· Adequate personnel training in leak prevention, containment and response.<br>· Ensure leak response and containment equipment is deployed or available as necessary for response | · Facility -specific occupational health and safety hazards should be identified based on job safety analysis or comprehensive hazard or risk assessment using established methodologies such as a hazard identification study [HAZID], hazard and operability study [HAZOP], or a scenario-based risk assessment [QRA].<br>· As a general approach, health and safety management planning should include the adoption of a systematic and structured approach for prevention and control of physical, chemical, and biological health and safety hazards<br>· Installation of an automatic Emergency Shutdown System that can detect and warn of the uncontrolled release of oxygen (including the presence of oxygen-enriched atmospheres in working areas) and initiate shutdown actions thus minimizing the duration of releases, and elimination of potential ignition sources<br>· Protection measures include worker training, work permit systems, use of personal protective equipment (PPE), and toxic gas detection systems with alarms.<br>· Avoiding potential sources of |

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| | level; that staff is adequately trained; and that equipment is maintained in a safe condition. The formation of a health and safety committee for the facility is recommended.<br>· A formal Permit to Work (PTW) system should be developed for the facilities. The PTW will ensure that all potentially hazardous work is carried out safely and ensures effective authorization of designated work, effective communication of the work to be carried out including hazards involved, and safe isolation procedures to be followed before commencing work.<br>· The facilities should be equipped, at a minimum, with specialized first aid providers (industrial pre-hospital care personnel) and the means to provide short-term remote patient care.<br>· LNG facilities should be designed, constructed, and operated according to international standards for the prevention and control of fire and explosion hazards, including provisions for safe distances between tanks in the facility and between the facility and adjacent buildings<br>· Training should be provided to educate workers regarding the hazards of contact with cold surfaces (e.g. cold burns), and personal protective equipment (PPE) (e.g. gloves, insulated clothing) should be provided as necessary.<br>· The design of the onshore facilities should reduce exposure | | ignition (e.g., by configuring the layout of piping to avoid spills over high temperature piping, equipment, and / or rotating machines) | | ignition (e.g., by configuring the layout of piping to avoid spills over high temperature piping, equipment, and / or rotating machines) |

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| | of personnel to chemical substances, fuels, and products containing hazardous substances.<br>· Facilities should develop and implement confined space entry procedures | | | | |
| **Community Health and Safety** | · Emphasizing safety aspects all actors<br>· Improving driving skills and requiring licensing of drivers<br>· Adopting limits for trip duration and arranging driver rosters to avoid overtiredness<br>· Avoiding dangerous routes and times of day to reduce the risk of accidents<br>· Use of speed control devices (governors) on trucks, and remote monitoring of driver actions<br>· Minimizing pedestrian interaction with construction vehicles<br>· Collaboration with local communities and responsible authorities to improve signage, visibility and overall safety of roads,<br>· Coordination with emergency responders to ensure that appropriate first aid is provided in the event of accidents<br>· Using locally sourced materials, whenever possible, to minimize transport distances. Locating associated facilities such as worker camps close to project sites and arranging worker bus transport to minimizing external traffic Training health workers in disease treatment<br>· Conducting immunization programs for workers in local<br>· communities to improve | · Emphasizing safety aspects all actors<br>· Improving driving skills and requiring licensing of drivers<br>· Adopting limits for trip duration and arranging driver rosters to avoid overtiredness<br>· Avoiding dangerous routes and times of day to reduce the risk of accidents<br>· Use of speed control devices (governors) on trucks, and remote monitoring of driver actions<br>· Minimizing pedestrian interaction with construction vehicles<br>· Collaboration with local communities and responsible authorities to improve signage, visibility and overall safety of roads<br>· Coordination with emergency responders to ensure that appropriate first aid is provided in the event of accidents<br>· Using locally sourced materials, whenever possible, to minimize transport distances. Locating associated facilities such as worker camps close to project sites and arranging<br>· worker bus transport to minimizing external traffic<br>· Training health workers in disease treatment<br>· Conducting immunization programs for workers in local communities to improve health and guard against infection<br>· Providing health services | · Emphasizing safety aspects all actors<br>· Improving driving skills and requiring licensing of drivers<br>· Adopting limits for trip duration and arranging driver rosters to avoid overtiredness<br>· Avoiding dangerous routes and times of day to reduce the risk of accidents<br>· Use of speed control devices (governors) on trucks, and remote monitoring of driver actions<br>· Minimizing pedestrian interaction with construction vehicles<br>· Collaboration with local communities and responsible authorities to improve signage, visibility and overall safety of roads,<br>· Coordination with emergency responders to ensure that appropriate first aid is provided in the event of accidents<br>· Using locally sourced materials, whenever possible, to minimize transport distances. 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| | health and guard against infection<br>• Providing health services<br>• Providing treatment through standard case management in on-site or community health care facilities. Ensuring ready access to medical treatment, confidentiality and appropriate care, particularly with respect to migrant workers<br>• Promoting collaboration with local authorities to enhance access of workers families and the community to public health services and promote immunization<br>• Prevention of larval and adult propagation through sanitary improvements and elimination of breeding habitats close to human settlements<br>• Elimination of unusable impounded water<br>• Increase in water velocity in natural and artificial channels<br>• Considering the application of residual insecticide to dormitory walls<br>• Implementation of integrated vector control programs<br>• Promoting use of repellents, clothing, netting, and other barriers to prevent insect bites<br>• Use of chemoprophylaxis drugs by non-immune workers and collaborating with public health officials to help eradicate disease reservoirs<br>• Monitoring and treatment of circulating and migrating populations to prevent disease reservoir spread<br>• Collaboration and exchange of in-kind services with other control programs in the project area to maximize beneficial | • Providing treatment through standard case management in on-site or community health care facilities. Ensuring ready access to medical treatment, confidentiality and appropriate care, particularly with respect to migrant workers<br>• Promoting collaboration with local authorities to enhance access of workers families and the community to public health services and promote immunization<br>• Prevention of larval and adult propagation through sanitary improvements and elimination of breeding habitats close to human settlements<br>• Elimination of unusable impounded water<br>• Increase in water velocity in natural and artificial channels<br>• Considering the application of residual insecticide to dormitory walls<br>• Implementation of integrated vector control programs<br>• Promoting use of repellents, clothing, netting, and other barriers to prevent insect bites<br>• Use of chemoprophylaxis drugs by non-immune workers and collaborating with public health officials to help eradicate disease reservoirs<br>• Monitoring and treatment of circulating and migrating populations to prevent disease reservoir spread<br>• Collaboration and exchange of in-kind services with other control programs in the project area to maximize beneficial effects<br>• Educating project personnel and area residents on risks, prevention, and available treatment | standard case management in on-site or community health care facilities. Ensuring ready access to medical treatment, confidentiality and appropriate care, particularly with respect to migrant workers<br>• Promoting collaboration with local authorities to enhance access of workers families and the community to public health services and promote immunization<br>• Prevention of larval and adult propagation through sanitary improvements and elimination of breeding habitats close to human settlements<br>• Elimination of unusable impounded water<br>• Increase in water velocity in natural and artificial channels<br>• Considering the application of residual insecticide to dormitory walls<br>• Implementation of integrated vector control programs<br>• Promoting use of repellents, clothing, netting, and other barriers to prevent insect bites<br>• Use of chemoprophylaxis drugs by non-immune workers and collaborating with public health officials to help eradicate disease reservoirs<br>• □□Monitoring and treatment of circulating and migrating populations to prevent disease reservoir spread<br>• Collaboration and exchange of in-kind services with other control programs in the project area to maximize beneficial effects<br>• Educating project personnel and area residents on risks, prevention, and available treatment | standard case management in on-site or community health care facilities. 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Ensuring ready access to medical treatment, confidentiality and appropriate care, particularly with respect to migrant workers<br>• Promoting collaboration with local authorities to enhance access of workers families and the community to public health services and promote immunization<br>• Prevention of larval and adult propagation through sanitary improvements and elimination of breeding habitats close to human settlements<br>• Elimination of unusable impounded water<br>• Increase in water velocity in natural and artificial channels<br>• Considering the application of residual insecticide to dormitory walls<br>• Implementation of integrated vector control programs<br>• Promoting use of repellents, clothing, netting, and other barriers to prevent insect bites<br>• Use of chemoprophylaxis drugs by non-immune workers and collaborating with public health officials to help eradicate disease reservoirs<br>• Monitoring and treatment of circulating and migrating populations to prevent disease reservoir spread<br>• Collaboration and exchange of in-kind services with other control programs in the project area to maximize beneficial effects<br>• Educating project personnel and area residents on risks, prevention, and available treatment |

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| | effects<br>· Educating project personnel and area residents on risks, prevention, and available treatment | | | | |

*Source: PwC Consortium Analysis*

# 10.5. Planning Local Content

## 10.5.1. Local Content Development

Local content is becoming the most strategic determinant for acquiring a social license to operate, while leaving a positive legacy in a country. The Petroleum Exploration, Development and Production Bill (2014) defines *Local Content* as the use of Kenyan expertise, goods and services, people, businesses and financing for the systematic development of national capacity and capabilities for the enhancement of the Kenyan economy. In its basic definition it is the commitment to generate in country capability to support the long-term development of the emerging oil and gas sector; it represents the opportunity to maximize the use of local human capital, goods / materials resources and services, promote real and effective partnerships, as well as benefit local business and communities through:-

- Local business development (goods and services)
- Local employment (re-skilling, job development, redeployment)
- Creating sustainable local economic development

The oil and gas upstream sector is currently dominated by foreign investments in terms of supply of technical exploration and production skills, goods and services. On the other hand, local content is characterised by semi-skilled and unskilled labour and limited supply of goods and services. This implies that the cost of skilled labour, goods and supplies are high at the beginning but through a well-planned and structured local content strategy, the cost of local technical skills will be cheaper in the long run. The local trained technical workforce will lead to labour cost savings and also be available for future regional developments. The aim of the local content strategy is to reverse the dependence of the sector on international technical skills and supply of goods and services to the sector.

Consultations with companies undertaking oil exploration in the country, registered the following as key challenges or limiting factors in local content development that need to be addressed during the Master Plan period:-

- Un-competitiveness of local firms
- Limited relevant experience and technical capabilities
- Poor production quality and reliability
- Low compliance to international health, safety and environmental standards
- Weak public sector regulation and inefficient bureaucracies
- Defining the meaning of local content in the context of National and County Governments as a result of the devolved governance structure Cultural diversity, ethnicity and clanism

The abovementioned Petroleum Bill and Local Content draft regulations include all energy sources: electrical, mechanical, hydraulic, pneumatic, chemical, nuclear or thermal power for any use, and includes electricity, petroleum *(oil and gas activities)*, coal, geothermal, fluid, biomass and all its derivatives, municipal wastes, solar, wind and tidal wave power. The meaning, application and contextualisation of local content are facing major challenges from Counties and local communities that host upstream activities. It will be important to review and harmonise the proposed local content legislation, and consolidate it into one single Bill focusing on the oil and gas sector. A public participation process covering all areas with oil and gas potential, and the country at large will be required. Successful local content delivery will require all stakeholders (including County Governments and host communities) to become engaged in the general framework. Foreign investors should also be expected to use their supply chain systems to improve local content opportunities across all partners.

The draft Petroleum Exploration, Development and Production Bill and relevant draft regulations on the same Bill require that a long term and annual local content plan shall be developed by investors and contain the following sub-plans:

(a) Employment, Training and Succession Plan (including industrial attachment and apprenticeship);
(b) Research and Development Plan;
(c) Technology Transfer Plan;
(d) Legal Services Plan; and
(e) Financial and Insurance Services Plan

The existing draft law has specified minimum local content levels and requirements for goods and services for any energy operations in Kenya. The planned Upstream Petroleum Regulatory Authority under the Petroleum Exploration, Development and Production Bill (2014) shall monitor and enforce local content in upstream petroleum operations.

The private sector through oil and gas companies like Tullow are already working with the government to implement initiatives and programs which help new suppliers to develop their standards, processes and systems to support the oil and gas industry. For example, Tullow is currently financing Lodwar Polytechnic to develop semi-skilled and skilled labour in Turkana. The company also has enterprise development initiatives where their international suppliers train local firms on the required standards and best practices to enable them compete for contracts effectively. Ghana is a good case study to benchmark against with regard to local content implementation due to the speed of enactment of legislation. On the other hand, local content legislation came into place in Nigeria in 2010, whereas exploration begun in the 1930s. Given that this legislation was implemented long after Nigeria's oil and gas sector had already entered the production stage, significant job and business opportunities which could have accrued to the country via such legislation were lost. It is significant to note that opportunities for local content in the upstream oil and gas sub sector are highest during the development phase.

## 10.6. Multiplier Effects of Oil and Gas Sector Development

Nations that have developed oil and gas resources have typically experienced strong economic growth from revenues generated from exploration and production activities. Other than direct revenues there are other indirect benefits that a nation can achieve. By adopting a targeted approach in developing its oil and gas resources, the following spill -over effects and more can be expected in Kenya.

### 10.6.1. Increased local supplier activity and stimulation of other sectors

The oil and gas sector in nature has high capital and operation requirements whose procurement will have a spill-over effect throughout the Kenyan economy. Procurement of capital goods, consumables and services can act as a multiplier for local economic development which will contribute to employment, skills strengthening as well as development of local suppliers. The local supplier base and enterprises will also benefit from technology transfer through cooperation with foreign suppliers which will bridge the gap of local technical capacity limitations. Local supplier activities could also be enhanced through preferential supplier targets for locally owned companies through production and operating agreements with the government where goods and services are of comparable quality and available in amounts similar to international materials and services. Furthermore, the use of local supplies may in theory provide for a more financially competitive arrangement because of cheaper labour available in Kenya as well as close proximity of local suppliers to a project.

Through long term cooperation between domestic and foreign suppliers, domestic capabilities will be strengthened which can then lead to the growth of a local manufacturing, fabrication and services sectors that can produce goods which would otherwise need to be imported.

Other than increased activity by local suppliers in the oil and gas industry, suppliers within other sectors are set to benefit from demand for other goods and service along oil and gas supply corridors. This includes demand for housing and accommodation at exploration sites and administrative stations, demand for food and other supplies, need for transportation, insurance, medical services among others. Less developed areas in Northern Kenya where exploration activities are ongoing are set to be immediate beneficiaries from these economic activities. We can also expect that such developments will increase the circulation of money in these areas further stirring activities within smaller scale businesses which will directly impact households' income improving living standards.

### 10.6.2. Job creation and increased technical skills

The oil and gas sector employs innovative technology and proprietary intellectual property. Oil and gas development in Kenya can have a flow on effects of knowledge transfer to businesses and the labour force. The technological capability that can be transferred varies from engineering, e-procurement, construction among others. These capabilities can be transferred through appropriate programs spanning from training of local staff by oil and gas employers to research and development cooperation between oil and gas players and local universities.

At the moment, sourcing the right people and managing human capital in the oil and gas sector is a concern that will need to be addressed in order to increase local content into the sector. The need for local manpower participation will lead to the emergence of relevant training opportunities within institutions of higher learning. Kenya has several well established public and private universities and technical institutions that are placed to provide the relevant training. As discussed above, through partnerships with international institutions and oil and gas market players, these institutions will have the capability to develop the curricula and put together a faculty to provide the required training.

At present a number of universities and companies are providing oil and gas training. Kenyatta University has started a programme on Petroleum Engineering while Moi University is offering chemical engineering courses. In addition, Kenyans can now receive training on petroleum measurement for custody transfer, loss control, safety and risk management from companies such as SGD and KK security. Other strategies that will foster the multiplier effects include hands-on industry training though job placement for students and young and mid-career professionals. The local community will also benefit from scholarships such as the Tullow oil scholarships for student to study in other international universities .Similar initiatives and more will build a skilled local work force that can export its services in the region.

## *10.6.3. Opening up of Northern Kenya*

Oil and gas will further open up the currently marginalized areas of Northern Kenya where oil and gas activities are ongoing. Through local content requirements, corporate social responsibility and Government spend on infrastructure, we can expect the northern part of Kenya to open up to the rest of the country. Development of road, power and water infrastructure will result in increased business activity that will be supported by a market created by oil and gas activities in the area.

A key impediment to building local capabilities in oil and gas exploration areas is low access to education and loss of pupils as they advance through the school levels. In Turkana county some of the contributing adherences to education access has been the lack of proper infrastructure, poor security as well as the county's demographics which is large in land mass (68,307 Sq.Km) and low in population density (13 persons per Sq.Km) as per the 2009 census. As the region opens up to oil and gas exploration and with changing a culture in favour of schooling we expect increased access to education which will position the community to take part in oil and gas activities in the county and countrywide.

**Primary School Enrolment Turkana County,2007 - 2012**

| | 2007 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|
| Primary School Enrolment | 53,471 | 53,625 | 60,839 | 64,456 | 67,731 | 125,785 |
| Secondary School Enrolment | 5,015 | 5,676 | 6,257 | 7,025 | 6,824 | 7,920 |

Loss of Students through the system

*Source: Kenya National Bureau of Statistics*

Kenya's development of oil and gas resources will however need to take a targeted approach to ensure equitable distribution of resources and other benefits to the local community. Issues around land rights, community displacement and distribution of oil resources should be implemented in consultation and partnership with governing bodies in the central Government, county Government and the local community to ensure that the rights of the communities in question are preserved.

## *10.6.4. Emerging Technologies*

As a multiplier effect of oil and gas exploration, a number of emerging technologies could emerge along the oil and gas value chain which would further develop a domestic market for oil and gas products.

To effectively promote emerging technologies the government may need to create an enabling environment that allows the private sector to innovate, in addition to making the necessary investments in infrastructure. Chapter 7 explores the possibility of using CNG (and LNG) to fuel vehicles, and highlights the need for the government's investment in the transportation and storage infrastructure as well as public transportation fleets. Likewise Chapter 6, considers the need for investment in LPG facilities, and an LPG development plan, to ensure availability and affordable product prices that can promote its use as a household fuel.

In meeting the demands of Kenyans while considering the demographics of the target consumers, some innovative products have already been rolled out in the market. Below we briefly profile an LPG product, “Pima Gas” to illustrate how emerging technologies can develop a domestic market for oil and gas products. We also consider the challenges faced by the private sector in applying emerging technology in the Kenyan market, and how GoK can support and encourage similar innovation in future.

“Pima Gas” was developed by a Kenyan firm, Premier Gas with financing from the IFC and was launched in 2012. It seeks to promote LPG use as a cooking fuel among the mass market with particular focus on rural households and lower socio-economic groups in urban areas by solving key distribution, hardware and affordability issues.

Pima Gas pioneered a 1 kg cylinder in the market as well as mobile LPG refill unit that allows for partial filling of cylinders. This feature allows consumers to refill a minimum of KES 50 at a time, at a cost of KES 300 per kg of LPG (as of 2012). Prior to this, the smallest cylinder in the market was 3kg. Pima Gas therefore addresses issues of affordability for base of the pyramid consumers given the increased portability of the cylinder due to its small size, and the potential for convenient distribution using mobile refilling units. Pima Gas is competitive with biomass and kerosene which are the two leading energy sources for households in Kenya. By incorporating local traders as authorized Pima Gas vendors, this emerging technology also support the development of small businesses, particularly in rural areas and lower income urban areas.

GoK can support similar innovations in the oil and gas sector by creating an enabling investment environment. Furthermore, GoK should consider policies that promote the best use of oil and gas products domestically. For example, to encourage LPG use, GoK can reduce taxes on both LPG and LPG appliances to make it more affordable, whilst increasing taxes on kerosene (as proposed by MoEP to the National Treasury).

In addition, GoK should ensure effective action is taken on persons engaged in illegal LPG cylinder refilling in order to protect both consumers and private investors in the sector. This would have the added benefit of reducing adulteration of diesel and gasoline using kerosene, by eliminating the financial incentive (MoEP estimates that 50% of kerosene used in Kenya is used for adulteration).

In addition to reducing tax revenue leakage by minimising fuel adulteration, such a policy would also reduce the health risks associated with long term exposure to kerosene, as well as contribute to a more efficient transportation system by eliminating the cost associated with vehicle maintenance as a result of adulterated fuel.

## 10.7. Recommendations

The recommendations herein are divided into four wide areas:-

- Institutional and Environmental Policy Recommendations
- Mitigating Social Impacts
- General Environmental and Social Impact Management Plan
- Developing Local Content

### 10.7.1. *Institutional and Environmental Policy Recommendations*

- Some existing policies, institutional frameworks and laws require revision (as highlighted above), as they were enacted before the discovery of oil and gas in the country, the 2010 constitution and the devolution process. For example, the development of land leasing regulations / guidelines for private and community land types for mining, oil and gas exploration and production is urgently needed.
- Strengthening institutional capacity in environmental management of the oil and gas industry both at National and County levels. Improving and building capacity on EIA follow-up, monitoring mechanisms and information dissemination to ensure enforcement and compliance to laws. This also includes development of procedures assessing damages and environmental liabilities.
- Undertake a National Environmental and Social Strategic Assessment (SESA) to cover existing policies, this Study and other existing petroleum sectorial plans and development programmes. The National Environment Management Authority (NEMA) should lead in the process that will cover all the petroleum sedimentary basins. A comprehensive Environmental and Social Management Plan for upstream, mid-stream and downstream impacts will guide future investments for this sector.
- Streamlining, reviewing and updating environmental policies, legal and regulatory status to ensure that the country achieves sound oil and gas policy sufficiently. The development of national SESA / SEA, EIA and Audit guidelines for the petroleum sector by ERC through the support of NEMA and other Government agencies is critical. This also applies to formulation of EHS guidelines for the upstream and mid-stream sectors.
- Harmonize all policy and legal local content initiatives and existing policy and legal drafts by developing them into one comprehensive National Local Content Strategy and Bill for the whole petroleum sector through a wide participatory process.
- Strengthening public consultation and involvement procedures by developing and implementing a public participation and consultation manual for oil and gas sector.
- Develop and implement a communication strategy on the process and timelines associated with exploration and development of the petroleum sector to manage expectations of local communities / leaders and Kenyan people in general.
- Integrate / harmonise poverty and infrastructural development programmes with those in the oil and gas sector.
- Support for environmental monitoring, protection programs and technology transfer / capacity building using a portion of oil and gas revenues. Enhance NEMA's and ERC's budgets to enable effective management of the developing sector.
- Embrace and implement cleaner technologies for the oil and gas sector.
- GoK should facilitate, support and engage with private sector initiatives / organisations. For example, the Oil Spill Mutual Aid Group (OSMAG), Kenya Oil and Gas Association (KOGA) amongst others.
- Development of a National Communication Strategy for Oil and Gas Sector and implementation of a Public Education Awareness Program.
- Mainstream gender issues in petroleum sector policies in order to ensure ample regulation to address gender issues in the growing petroleum sector. This must also be extended to the proposed local content strategy. Access to jobs and opportunities should be enhanced for all gender groups, people living with disabilities, marginalised and minority communities.
- While environmental planning and management tools like EIA, SEA, Environmental Monitoring and Audits exist, developing good governance on environmental and social investment principles in Government, communities and private sector in terms of benefit sharing, will support protection of the environment and ensure sustainable growth of the sector.
- The period of obtaining a NEMA SEA approval should be reduced. The 0.1% fee (based on project value) for EIA license applications is high, especially given the risk inherent in exploration activities. The law requires

review to reduce the SEA approval period to below 4 months. The risk inherent in exploration activities should also be considered in reviewing EIA licence application fees.
- Revision of the recently enacted resettlement regulations to comply with international standards.
- GoK needs to enhance its security strategy to ensure adequate security personnel and resources are assigned to both local communities and oil and gas installations, for sustainability of the petroleum sector.

## 10.7.2. *Mitigating Social Impacts*

Negative outcomes of resource extraction are not inevitable in the oil and gas sector; however, they can be tackled and mitigated through effective strategies, international social performance standards and best practices, review of legal frameworks and policies in the following areas:

### 10.7.2.1. *Legal and social agreements*

Legal and social agreements on responsibilities and commitments of parties, compensation, local content, security standards, sharing and use of revenues, applicability of National and County laws, development of National and County-level infrastructure, employment and sharing of business opportunities should be formulated, negotiated and implemented for the prosperity of the country and all its people. Lessons learned from Nigeria and other countries indicate that goals of sustainable development cannot be achieved where damages to environment affects adversely local livelihoods. Due to the close relationship between management of environmental and social impacts and the gross national income, it will be important to prioritise the former to ensure sustainability of the sector and general economy of the country.

### *10.7.2.2. Public consultation and information disclosure*

This should be guided by international guidelines in areas of land acquisition, resettlement, compensation, SEA / ESIA and Environmental Audit processes. The extent and level of information disclosure should be agreed upon to protect Government, investors and community interests.

The key stakeholders that are expected to be active and involved in shaping this emerging sector in the country during the implementation period of this Study include the following:-

- GoK (including all its relevant public agencies and institutions)
- County Governments
- Foreign Governments / International Development Partners
- Local and international private and public oil and gas companies
- Lending agencies
- Contractors
- Non-Governmental Organisations (NGOs) and Community-Based Organisations (CBOs)
- Local / indigenous communities and their traditional and political leadership

Early consultations and clear policy definitions on the roles of each of these stakeholders in the oil and gas exploration and production projects cycle is of critical importance. This should be through various environmental and social planning and development tools and approaches like ESIA / EIA, Environmental Audits and CSR or social investments programmes. Consultations on standards and practices of each of these stakeholders should generally be guided by international standard guidelines.

### *10.7.2.3. Resettlement and compensation of project affected persons*

Resettlement of indigenous and vulnerable populations will be required both in upstream and mid-stream projects that will require land for long-term investments and infrastructure, temporary use or as provision for way leaves, for example for power transmission lines and pipelines. Systematic and step-by-step identification of project impacts and affected populations through mapping, census of project affected people (PAPs), inventory of affected assets, socioeconomic studies of PAPs , analysis of surveys and studies, consultation with affected people concerning assistance benefits and development opportunities should be undertaken. Legal frameworks guiding compensation and relevant for the petroleum sector should be developed based on constitutional and land legal guidelines. The guidelines should take into consideration resettlement assistance and livelihood, budget and implementation schedules, organisational responsibilities, consultation and participation procedures, grievance redress mechanisms, and monitoring and evaluation systems. International IFC Environmental and Social Performance Standards (see Summary Box below) provides a yardstick for national frameworks.

*Figure 10.1: IFC Environmental and social performance standards summary box*

**☐PS 1: Assessment and Management of Environmental and Social Risks and Impacts**
**☐PS 2: Labour and Working Conditions**
**☐PS 3: Resource Efficiency and Pollution Prevention**
**☐PS 4: Community Health, Safety, and Security**
**☐PS 5: Land Acquisition and Involuntary Resettlement**
**☐PS 6: Biodiversity Conservation and Sustainable Management of Living Natural Resources**
**☐PS 7: Indigenous Peoples**
**☐PS 8: Cultural Heritage**

**Note:** *Performance Standard 1 establishes the importance of (i) integrated assessment to identify the environmental and social impacts, risks, and opportunities of projects; (ii) effective community engagement through disclosure of project-related information and consultation with local communities on matters that directly affect them; and (iii) the client's management of environmental and social performance throughout the life of the project. Performance Standards 2 through 8 establish objectives and requirements to avoid, minimize, and where residual impacts remain, to compensate/offset for risks and impacts to workers, Affected Communities, and the environment. While all relevant environmental and social risks and potential impacts should be considered as part of the assessment, Performance Standards 2 through 8 describes potential environmental and social risks and impacts that will require particular attention. Where environmental or social risks and impacts are identified, the investors will be required to manage them through local Environmental legal framework with reference to these standards where national guidelines do not exist.*

*Source: IFC, 2012*

### 10.7.2.4. *Preservation of cultural properties and resources*

This includes sites having archaeological, historical, traditional religious and unique natural values. Social-cultural surveys need to be undertaken to document such sites for preservation and utilisation for tourism and eco-tourism purposes. The county Governments should adopt a leading role in this activity because of their strategic position, whereas GoK can assist with technical support.

### 10.7.2.5. *Employment and labour relations and practices*

Labour unrests in the upstream and mid-stream projects being undertaken have been reported. They are attributed to discrepancies in pay and contracts, living and working conditions, termination of employment contracts, lack of fair and transparent human resource management systems (hiring, training and management), and political interference. Application of transparent and legal policies and procedures that encourage and promote competitiveness at National and County levels will need to be implemented to mitigate this problem.

### 10.7.2.6. *Land Use Planning and Integrated Infrastructural Development*

Most of the areas targeted for oil and gas infrastructural development have markets with limited facilities and services. Oil and gas activities have already witnessed social impacts like immigration, social equity / parity, local food security, housing, land use and values, unplanned urbanisation and growth of market centres, and increased demand for education. Current development plans are based on newly developed physical plans at the county level using Integrated Infrastructural Development (IID) approach. This approach through public-private partnerships and stakeholders engagement, shall provide oil and gas exploration and production sites (potential future growth centres) with well-planned infrastructural facilities like power distribution networks, water, health and sanitation, education, telecommunication, drainage and pollution control facilities, roads, financial services, raw materials supply, storage and marketing outlets, transport, security systems, land use planning, natural resources management, common service facilities and technological back up services. Communities need to be involved in planning of all forms of developments due to land issues (for example, in the case of the wayleave required for crude oil pipelines). Both National and county Governments must work closely in augmenting each other in infrastructural development. This will create opportunities for the private sector to make profitable investments.

### 10.7.2.7. *Revenue and opportunity sharing mechanisms*

In determining revenue and opportunity sharing mechanisms there is need to develop workable formulae that consider a national sector. While formulae cascaded down to the sub-county level may benefit host communities in the short term, if exploration and production develops in other regions, mobility and career progression for workers may be hampered, while investors will face significant training and efficiency related costs at new sites.

### 10.7.2.8. *Constitutional and community human rights*

In reference to the provisions of the Constitution of Kenya, 2010, the draft petroleum law (Petroleum Exploration, Development and Production Bill, 2014) recognises the following fundamental community rights:

- Be informed prior to carrying out any upstream petroleum operations within their county and sub-county;
- Put forward any inquiries, interrogate planned activities which directly or indirectly affect their interaction with the ecosystem during the preliminary phase of awarding of petroleum licences for consideration;
- Adequate compensation for land taken over for upstream petroleum operations in accordance with relevant land laws and the constitution;
- Be compensated by any contractor who causes environmental damage and / or pollution;
- Be compensated for any injury and / or illness directly or indirectly related to the petroleum operations if the contractor was in a position to take measures to prevent the occurrence of the same;
- Compensation for damage to property and lost source of revenue or livelihood as a result of upstream petroleum operations taking place in their immediate surroundings;
- Be educated and sensitized on upstream petroleum operations within their county and sub-county; and
- Participate in planning for corporate social responsibility (CSR) projects that are to be implemented within the community by the contractor in consultation with the national and county Governments.

### 10.7.2.9. *Institutional Transparency and Environmental Accountability*

In the quest to create a dynamic oil and gas industry, institutional transparency and accountability must be promoted. Transparency is essential in building and maintaining public dialogue and increasing public awareness about the GoK's development role and mission in the petroleum sector. It is also critical for enhancing good governance, accountability, and development effectiveness. The harmonization of political leadership with civil society, media and other opinion shapers, as well as the private sector to pursue ethical leadership and robust public management models will contribute significantly to achieving these best practices. Empowering existing institutions tasked with providing checks and balances (for example the National Assembly, the Senate and the Judiciary), should contribute to the creation of a good fiscal decentralisation with accountability and community driven development.

All stakeholders should have a moral and constitutional duty to apply best practices in public consultation and involvement, building of sustainable partnerships and the integration of social concerns into oil and gas project planning and design, appraisal, construction, operation and decommissioning processes. All key stakeholders of the sector must undertake management of social issues through public participation and partnerships. It is important for future investments in the upstream and midstream sub-sectors to have community support, acceptance and informed consent as part of their foundation. The development and continuous review of existing environmental, regulatory and monitoring frameworks with determination of liability costs during decommissioning, closure, and abandonment processes, will support the sector in the long term by protecting future generations.

### 10.7.2.10. *Gender and Vulnerability in the Petroleum Sector*

Kenya is a signatory to various international and regional protocols such as the Convention for the Elimination of Discrimination Against Women (CEDAW) and the Africa Protocol on Women's Rights. As a result of the discovery of oil and gas in Kenya, a number of legal and institutional frameworks have been developed for the exploration, production and management of the industry, but there is no clear demonstration or commitment to gender responsiveness in these legal and institutional considerations. An analysis of the oil and gas value chain in Kenya shows a focus more on the scientific, technical and economic aspects. Often, men have better access to benefits via employment and supplies, while the costs such as family / social disruption fall most heavily on women.

The Kenyan constitution provides fundamental policy guidelines to protect male and female citizens from gender imbalance. Gender imbalance experienced elsewhere on the African continent has exacerbated inequality. It has resulted in costly social conflicts and entrenchment of poverty in oil producing areas and widened gaps between the rich and the poor, who are mostly women, children and the youth.

These historical lessons from some African countries should serve as guidelines to strengthen citizen participation, including women's rights and gender oriented organizations in policy dialogues in the sector. Strong citizens' participation will contribute to better management of the industry and ensure livelihood diversification and sustainability. Access to jobs and opportunities should be enhanced for all gender groups, people living with disabilities, marginalised, and minority communities.

### 10.7.3. General Environmental and Social Management Plan

The Government has developed environmental planning and management tools that inform decision making in the environment sector. These include: Strategic Environmental Assessment (SEA), Environmental Impact Assessment (EIA), and Environmental Audits (EAs). These tools currently play critical roles in decision making and guiding impact mitigation strategies. However, other tools like Cost Benefit Analyses (CBA) and Social Impact Assessments (SIA) are yet to be integrated fully into the existing environmental laws. Below is a policy level ESMP that summarises key areas that need attention during the Master Planning period. The SESA process will give specific mitigation measures to address impacts expected from the sector.

*Table 10.6: Policy level environmental and social management plan*

| Environmental and Social Concerns | Proposed Policy Mitigation Measures | Plan Period | Responsibility |
|---|---|---|---|
| Insufficient Environmental and Social Impact Analysis Procedures | ▪ Formulation of Environmental and Social Impact Assessment Procedures<br>▪ Manuals for SEA/SESA, ESIA and EA for the Upstream (onshore and offshore), Mid-Stream and Downstream sectors | Short Term / Urgent | ▪ NEMA |
| Lack of Environmental, Health, and Safety (EHS) harmonised guidelines for the Petroleum (Oil and Gas) Sector | ▪ Development of Environmental, Health, and Safety (EHS) Guidelines for Upstream (onshore and offshore), Mid-Stream and Downstream Exploration, Transportation, Processing and Distribution and Marketing / Retail Facilities or Networks | Short Term / Urgent | ▪ NEMA<br>▪ DOHS<br>▪ ERC |
| Consultation and disclosure of information mechanisms | ▪ Develop and implement consultation and disclosure of information mechanisms, assessing of future liability risks, and ensuring adequate EIA monitoring and follow-up.<br>▪ Disclosure of incomes / revenues | Continuous | ▪ GoK<br>▪ MoEP<br>▪ National Treasury<br>▪ NEMA |
| Inadequate enforcement and compliance to petroleum industry environmental, health and safety policies and laws | ▪ Build human, technical and financial capacity of NEMA and other Government agencies at National and County Levels | Continuous | ▪ GoK<br>▪ County Governments<br>▪ Development Partners<br>▪ Private Sector |

| | | | |
|---|---|---|---|
| Land degradation and biodiversity | ▪ Review and implement the National Land Policy<br>▪ Review and enact the Community Land Bill to address oil and gas concerns<br>▪ Review and publication of the land resettlement policy guidelines and legislation<br>▪ Finalization of ASAL policy & guidelines<br>▪ Develop Land use Management Plans | Continuous | ▪ GoK<br>▪ Ministry of Lands, Housing and Urban Development<br>▪ County Governments |
| Water, Fisheries and wetlands Resources pollution | ▪ Review water quality regulation, 2006<br>▪ Develop mechanism for Payment for Ecosystem Services (PES)<br>▪ Review and Finalize Policy on trans-boundary water resources<br>▪ Review and finalise wetlands protection policy - Review of Water Master Plan<br>▪ Enforce Water Act, Water & Waste Management Regulations<br>▪ Support aquaculture projects as alternative source of livelihoods<br>▪ Control Leaks and Oil spills, land and water contamination/ pollution | Short Term / Urgent | ▪ Ministry of Environment, Water and Natural Resources<br>▪ NEMA<br>▪ Project Proponents |
| Threats to Wildlife and Forestry Resources | ▪ Review and finalise the Forest Act<br>▪ Enforce the Forest and Wildlife Acts and Policies<br>▪ Development monitoring programmes | Continuous | ▪ KFS<br>▪ KWS<br>▪ DRSRS |
| Threats to Coastal and Marine Resources | ▪ Enforce EMCA, 1999; Water Act & Water Quality Regulations , Forest and Wildlife and OHS Acts | Continuous | ▪ NEMA<br>▪ KFS<br>▪ KWS<br>▪ DOHS |
| Impacts to Livestock production | ▪ Support livestock production programmes<br>▪ Initiate irrigation schemes for livestock farmers<br>▪ Drilling more borehole to support the livestock | Continuous | ▪ Ministry of Agriculture<br>▪ Development partners<br>▪ Private investors |
| Human settlement and infrastructure | ▪ All plans, policies and programmes to undergo SESA<br>▪ All projects to undergo ESIA and Audits as per EMCA, 1999<br>▪ Monitoring and Enforcement of environmental and social legislation | Continuous | ▪ Project Proponents<br>▪ Private Investors<br>▪ NEMA |
| Air Pollution and Climate Change Impacts | ▪ Review and finalise the Climate Change Bill<br>▪ Mainstream climate change impacts and mitigation measures<br>▪ Review Air Quality Control Regulations<br>▪ Enforcement of laws to control air pollution and gas flaring | Continuous | ▪ Ministry of Environment, Water and Natural Resources<br>▪ Project Proponents<br>▪ Private Investors<br>▪ NEMA |

| | | | |
|---|---|---|---|
| Environmental governance and institutional arrangement | ▪ Establishment of Directorate of Petroleum and Environment at NEMA<br>▪ Review of EMCA 1999 and subsidiary legislation to fill legal gaps in the petroleum sector | Short Term / Urgent | ▪ Ministry of Environment, Water and Natural Resources<br>▪ NEMA |
| Waste Management for onshore and offshore developments | ▪ Review waste management regulations to include legal guidelines on the management of special wastes from the oil and gas sectors in the upstream, mid-stream and downstream<br>▪ Establish waste treatment and disposal facilities for onshore and offshore oil and gas exploration and production developments through PPPs, | Short Term / Urgent and Continuous | ▪ Ministry of Environment, Water and Natural Resources<br>▪ NEMA<br>▪ Private Investors |
| Health and Safety | ▪ Review OSHA, 2007 and develop EHS guidelines for the upstream, mid-stream and downstream sectors | Short Term / Urgent | ▪ DOHS<br>▪ Ministry of Environment, Water and Natural Resources<br>▪ NEMA |
| Disaster Management and Emergency Preparedness | ▪ Review and finalise the National Oil Spill Response Contingency Plan<br>▪ Oil Spill and Accidents Response Capacity building | Short Term / Urgent | ▪ Kenya National Disaster Operation Centre (NDOC)<br>▪ KMA<br>▪ NEMA<br>▪ Private Sector |
| Social Impacts Management | ▪ Develop and implement local content strategy and legislation for oil and gas sector<br>▪ Development of a communication strategy for the sector<br>▪ Initiate Corporate Social Responsibility projects | Short Term / Urgent | ▪ National Government<br>▪ MoEP<br>▪ Private investors/ project proponent |

*Source: PwC Consortium Analysis*

## 10.7.4. Developing Local Content

It is recommended that the sector stakeholders within the country should seek to maximise the benefits of oil and gas wealth generation through a comprehensive platform, including:

- The use of local expertise, goods and services, labour (including skilled and semi-skilled) and financing in the oil and gas industry value chain. Efforts to encourage local value addition on a no-subsidy basis should also be encouraged.

- Develop local capability in the oil and gas value chain through education, technical skills and relevant expertise development, transfer of technology and know-how, and active research and development.

- Target an agreed level of local participation and investment in all aspects of the oil and gas industry value chain. GoK and all stakeholders should work to enhance the participation of the local private sector, civil society, academia, local communities, women's organisations, and other affected groups in the decision-making processes to ensure effective governance of the oil and gas sector. The National Government should design and implement a framework for working with the private sector to put in place environmental and social performance standards, achieve local content regulations and integrate their corporate social responsibility objectives with Kenya's national and county development plans.

- **Public communication strategy:** There is need for upstream players and Government (both National and County-level) to manage expectations of local communities and their leaders and invest in communication about the process and timelines associated with exploration and development. Implementation of a public communication strategy, along with transparency will be the primary tools for controlling misinformation by explaining the importance of petroleum exploration and development for the Kenyan people, especially those in rural areas. This strategy will also be a key tool in achieving local community 'buy-in' (social licence) for further exploration and development, and consequently pre-empt disruptions to upstream operations. GoK should ensure transparency and access to information regarding its vision, strategies, decision-making processes, revenue realisation and utilisation, and development priorities. Basic information on the outlook of the sector needs to be clear and accessible, for example, how many and what type of job / business opportunities will be created over the next year and beyond, and what are the factors that would alter this / put this at risk.

- **Public consultations and stakeholder engagement:** Engagement between investors, Government, local leaders and employees should be continuous and undertaken at regular intervals to ensure smooth operation of activities and faster development of the sector. Transparency and responsiveness to requests for information and concerns from the local community and environmental civil society groups will be important to combat misinformation.

- **Revenue allocation:** A portion of the Government's revenues from oil and gas activities should be allocated to the counties and communities directly affected by such operations. This could help address development of rural livelihoods and economies as well as provide funding to mitigate any potential adverse environmental and social impacts, particularly considering that majority of Kenya's oil and gas as well as mineral exploration activity is carried out in marginal, relatively under-developed areas.

- **Local Content National Strategy:** through a participatory process, GoK needs to fast-track the development of a local content strategy and sessional paper for the oil and gas sector in Kenya. The context of local content under a devolved Government system, workforce and supplier capacity development, regulatory requirements, business drivers of the sector, and management of stakeholder expectations should all inform development of this strategy. Expedited implementation of a local content strategy will enable GoK to invest in capacity building, ahead of the development stage where most of the job and business opportunities are likely to occur. It is important to note that increasingly, upstream investors consider well implemented local content to have a positive financial and social impact on their businesses when compared with internationally sourced goods and services. Therefore, in developing a local content strategy, as well as the legislation to support its achievement, GoK should work with upstream investors, and other stakeholders to gain further insight on the opportunities, challenges and areas requiring joint investment in capacity building.

- **Local content legislation and management of expectations:** Local content on oil and gas legislation should stand on its own as a separate Act of Parliament to avoid unnecessary conflict with the Kenya Constitution, other relevant and existing local content policies and proposed legislation within the MoEP and other GoK agencies. The legislation also needs to set a realistic path to achieve the targets set out. While the focus should be on 'National Content' because all natural resources belong to all the people of Kenya, the local communities (hosting sector operations) should be empowered to competitively access the opportunities in the sector. Expectations of local communities who are defining local content as community specific input should be managed through nationhood sensitisation programmes. Consultations and outreach programmes to build trust among the industry, Governments, civil society organisations and local communities through the creation / implementation of regional livelihood development programs will also supplement the process. Development of a community strategy is of critical need; this along with the implementation and continuous monitoring of the local content strategy is important in managing expectations and building trust among stakeholders.

- **Community Development Programmes Approach:** The oil and gas companies should work closely with local provincial administration, community leaders, civil society organisations and National and County Governments to initiate short, medium and long-term interventions that can improve the communities' socioeconomic well-being. GoK should develop a mechanism to facilitate such engagement.

This in effect will make the host communities identify with and appreciate the exploration and production projects and 'own' them, thus leading to 'social licence', increased prosperity and participation in critical initiatives.

- **Periodical Baseline Studies:** The National Government in collaboration with the County Governments and upstream investors should undertake periodical baseline studies in oil and gas potential areas to determine the skills and supplies available in the market both nationally and at the county level. This will help determine what can be sourced locally and where international suppliers can partner with Kenyan firms to ensure local capacity is built over time. This will provide a framework for various Government agencies, and public and private educational institutions to develop and implement capacity building investment programmes in an informed manner. Upstream players will also benefit from the information from such studies in planning their corporate social responsibility or community social investment projects.

# Appendix A. - Terms of Reference

*Table A- 1: ToR checklist*

| Scope of the Consultancy | Addressed under Section |
|---|---|
| 1. Benchmarking / Case Studies: benchmark Kenya's current market conditions with a group of comparable countries with respect to the trajectory followed to develop an oil and gas sector for sustainable development impacts; Review case studies and present learning and implications for Kenya. | Chapter 9 |
| 2. Review and validate existing policies, plans and studies made available by relevant Ministries and Agencies of the GoK (e.g. Energy and Petroleum, Devolution and Planning, National Treasury, Transport and Infrastructure, Environment, Water and Natural Resource, Industrialization and Enterprise Development etc.). Gaps in the GoK's policy framework about key aspects of the oil and gas sector (upstream and downstream) should be identified. | Chapters 3, 4, 5, 6, 7, 8 and 10 |
| 3. Define domestic, regional export (neighbouring countries) and global export (LNG) opportunities to monetize oil and natural gas over a period until 2040. Potential domestic markets may include but not be limited to a refinery, petrochemical industry, a fertilizer plant, industrial development (metals/heavy industry, light industry/commercial), gas-fired power, methane or LPG for households and CNG/LNG for transport. Regional opportunities may include export or transit of oil, gas and oil and gas products. Consider the spatial linkage between identified opportunities and sectoral plans to focus on potential growth poles/corridors. | Chapters 4,5, 6, and 7 |
| 4. Review of oil and gas reserves and resource potential: evaluate production and cost profiles of existing reserves and future resources (under exploration), based on data and reports made available by the GoK and on publications. Create supply scenarios to be used in this study. | Chapter 4 |
| 5. Review oil and gas developments in neighbouring countries such as Uganda, Tanzania, Mozambique and the republic of Southern Sudan and the opportunities this creates for Kenya. Create transit scenarios for oil, gas, as well as oil and gas products. | Chapters 4 and 5 |
| 6. Evaluate domestic, regional export and global export market opportunities for oil and gas from a current and future demand perspective. This will include a review of domestic and export markets for products that use gas as a feedstock and/or fuel. In this context the energy mix options (Kenya has significant geothermal potential, but is in many places dependent on biofuels) will be considered for domestic energy needs as well as | Chapters 4, 5, 6 and 7 |

| | | |
|---|---|---|
| | for regional power import/export. Prepare demand and cost scenarios to be used in this study. | |
| 7. | Identify investment and operational requirements for new or upgraded facilities and infrastructure to process, store or transport oil and gas to different market opportunities as well as for infrastructure in support of the development of a domestic oil and gas sector (e.g. roads, fleets, railways, pipelines, ports, industrial parks, telecommunications, water, power etc.). Evaluate alternative options, advice on locations and estimate capital expenditure. | Chapters 5, 6 and 7 |
| 8. | Quantify the cost to produce oil and gas at a reference point to be agreed. Quantify the most likely netback values of any market opportunity. Review potential gas pricing mechanisms by market sector. | Chapters 4 and 7 |
| 9. | Consider environmental (e.g. GHG emissions, impact on national parks and vulnerable areas, marine and terrestrial ecosystem and infra-structures) and social aspects (e.g. access to energy, energy security, health and safety, employment creation, land use, co-existence with tourism, fishing industry and communities, marine traffic, gender dimensions, potential for conflict) for each of the identified oil and gas value chains. | Chapter 10, and Appendix J |
| 10. | Consider indirect (non-monetary) value of identified market opportunities: multiplier effect of other parts of the economy, impact of jobs, services and facilities on communities, development of capabilities that can be transferred to other sectors for sustainability etc. | Chapters 3 and 10 |
| 11. | Evaluate the use of emerging technologies for small or remote domestic market development (supply remote cities, towns, industries, vehicular natural gas, etc.) as a way to spread the use of oil and natural gas products and the creation of small businesses. | Chapter 10 |
| 12. | Build a technical and economic/financial model of the oil value chain(s) and the gas value chain(s) to evaluate the opportunities to monetize oil and gas on a sound economic basis and evaluate infrastructure investment requirements to match supply and demand capacities. | Chapters 5, 6, 7 and Appendix K |
| 13. | Consider financial structures to secure required private and public investments. Identify potential constraints and solutions. | Chapter 8 |
| 14. | Consider human resource requirements for the effective development and management of the oil and gas sector. Identify potential constraints and solutions. | Chapter 10 |
| 15. | Define strategic alternatives for the development of the gas sector and evaluate these alternatives against monetary, developmental, social and environmental metrics. In consultation with the GoK, prepare a recommendation for a preferred strategy to maximize the (monetary, social and environmental) value of oil and gas resources in | Chapters 5, 6, and 7. |

| | | |
|---|---|---|
| | Kenya. Prepare provisional oil and gas allocation profiles for each market sector. Identify critical success factors. | |
| 16. | Support the GoK to formulate a Vision for the development of its oil and gas sector. | Chapters 4, 5, 6, 7, 8, 9 and 10. |
| 17. | The PMP may not be a complete technical plan for oil and gas sector development, rather, it will provide a detailed roadmap for strategic, policy and institutional decisions upon which investments can be designed and implemented in a fully coordinated manner. Prepare a decision hierarchy that is linked to uncertainties related to oil and gas resources and markets. The Consultant will be asked to indicate whether the outcome should be a fully integrated oil and gas master plan or plans for oil and gas separately that are aligned and synchronized. | Chapters 1, 4, 5, 6, 7, 8, and 10. |
| 18. | On-the-job Training: transfer knowledge on petroleum master planning to the GoK Steering Committee. Prepare selected GoK staff members to be able to update the economic/financial model when new information becomes available. | Appendix K |

# Appendix B. - List of Stakeholders that we have engaged

1. Ministry of Energy
2. World Bank
3. Energy Regulatory Commission (ERC)
4. Kenya Oil and Gas Association (KOGA) & member representatives
5. Tullow
6. Africa Oil
7. Total Exploration
8. BG Kenya
9. Zarara Oil and Gas Limited
10. Toyota Tsusho
11. Kenya Pipeline Company
12. National Oil Corporation of Kenya (NOCK)
13. Petroleum Institute of East Africa & member representatives
14. Kenya Petroleum Refineries Ltd. (KPRL)
15. KenGen
16. Kenya Ports Authority
17. National Environment Management Authority
18. Ministry of Devolution
19. Central Bureau of Statistics
20. Vision 2030 Secretariat
21. LAPSSET Corridor Development Authority (LCDA)
22. Cordaid
23. Information Centre for the Extractives Sector (ICES)
24. Attended Turkana Oil Issues Forum held in Eldoret incorporating National and County Government representatives, upstream companies, upstream sector labour representatives and local community representatives.
25. Econews Africa
26. Haki Jamii
27. Natural Resources Alliance of Kenya (KeNRA)
28. Kenya Human Rights Commission (KHRC)
29. The Nature Conservancy
30. Kenya Civil Society Platform on Oil and Gas (KCSPOG)
31. Natural Justice
32. World Wide Fund for Nature (WWF)
33. Oxfam
34. Kenya Land Alliance (KLA)
35. Institute of Human Rights and Business (IHRB)

# Appendix C. - Existing legislation governing Oil and Gas in Kenya

### 1. Vision 2030

The overall policy guidance for Kenya is Kenya Vision 2030 which was launched in 2008. It aims at transforming Kenya into “a newly industrializing, middle income country providing a high quality of life to all its citizens in a clean and secure environment”. The policy is anchored on three pillars, Economic, Social and Political. The important role which energy will play in the economic transformation of the country is recognized in the policy.

The Economic Pillar projects the country to maintain and sustain economic growth rate at 10% per annum over the next twenty five years. With increasing incomes and urbanisation, the demand for energy in the country will rise. To meet the increased demand for energy several measures have been proposed in the Vision 2030.

Energy is one of the infrastructural “enablers” of the three pillars of Kenya Vision 2030. ***The sector is expected to develop the energy policy, laws, regulations and infrastructure which are necessary to ensure that it plays its role for the country to meet the economic and social goals in the Vision.***

Petroleum and Electricity are the main sources of commercial energy in Kenya. At the national level, wood fuel and other biomass account for about 68% of the total primary energy consumption, followed by petroleum at 22%, electricity at 9% and others including coal at about less than 1%.

Kenya currently imports all its petroleum products requirements, mainly from oil producing countries in the Middle East (operations at the Kenya Petroleum Refineries were suspended in September 2013). Petroleum importation accounts for about 23% of the national import bill. The volume of petroleum products imported in the country annually is about 4 million tonnes which is equivalent to over 80,000barrelas per day.

### 2. The Constitution of Kenya, 2010

The new Constitution of Kenya, the basic law of the country, was promulgated in August 2010, establishing a two-tier system of Government for the country i.e. the National and the County Governments. The distribution of functions and powers between the two levels of Government are provided in Chapter Eleven and the Fourth Schedule of the Constitution.

In relation to the Energy Sector, Parts 1 and 2 of the Fourth Schedule provides the division of functions of the two Governments as follows:

*“5. The National Government is responsible for:*

*(a) Protection of the environment and natural resources with a view to establishing a durable and sustainable system of development including water protection, securing sufficient residual water, hydraulic engineering and the safety of dams*
*(b) Energy policy including electricity and gas reticulation and energy regulation; and*
*(c) Public investment.*

*6. The County Governments will be responsible for county planning and development including electricity and gas reticulation and energy regulation.”*

The new constitution required that all existing policies, laws and regulations be reviewed and amended to ensure that they are aligned with the constitution and to ensure that there are no ambiguities in the divisions of powers and responsibilities between the two levels of Government**.**

### 3. Sessional Paper No. 4 of 2004 on Energy

This is the principal policy framework under which the energy sector has been operating for the last ten years.

The sessional paper identified the technical, commercial and other challenges which were facing the various energy sub-sectors, and developed a policy framework and implementation strategies to address some of those challenges. The aspirations of the policy was to lay the framework upon which cost-effective, affordable and adequate quality energy services will be made available for the domestic economy up to the year 2023. The sessional paper outlined the energy policies and strategies to guide the sector. It also detailed the short, medium and long term implementation plans for electricity, fossil fuels (petroleum and coal), biomass energy and renewable energy sub-sectors.

The vision set out in this policy document was "***to promote equitable access to quality energy services at least cost while protecting the environment"*** and the Mission was "***to facilitate provision of clean, sustainable, affordable, reliable and secure energy services for national development while protecting the environment"***

The Sessional Paper stated the energy policies and strategies covering electricity, fossil fuels, biomass, other renewable, rural energy, and the related cross cutting issues. In the following sections we review the policies affecting downstream and upstream petroleum sub-sectors.

### 4. Downstream Petroleum

In the downstream petroleum subsector the policy objective in the sessional paper is ***"to ensure provision of adequate supply and distribution of petroleum products in all parts of the country at least cost"***. For this objective to be achieved it was realised that there was need for availability of storage, distribution and fuel dispensing facilities in all parts of the country to guarantee access to fuel while maintaining high quality standards of the facilities and petroleum products to protect consumer interests and the environment. The policy has recommended several implementation plans to improve the infrastructure for import handling, storage, transportation and distribution of petroleum products

In the legal and regulatory regime, it was recognised that then existing Petroleum Act, Cap 116, first enacted in 1948 but with major amendments in 1972, was inadequate to address the challenges in downstream petroleum operations. Such challenges were brought by the partial deregulation of the sub-sector in 1984 and developments in the technical and commercial environments among others. The Policy also recognized the conflicting roles played by the Ministry of Energy in both policy formulation and regulation of the sub-sector.

To address this situation, the policy proposed the establishment of the Energy Regulatory Commission with regulatory mandate for electricity, downstream petroleum and renewable energy.

### 5. Upstream Petroleum

In the upstream petroleum sub-sector, the policy objective as set out in the sessional paper is to ***"enhance an enabling environment through which petroleum exploration and associated resource development activities can be undertaken in an environmentally sound manner"***. The policy document acknowledged that the production sharing model contract embedded in the Petroleum (Exploration and Production) Regulations, 1984, issued under the Petroleum (Exploration and Production) Act, cap 308 of 1984 had helped to attract exploration companies to Kenya and recommended its retention.

The Government undertook to carry out minimum exploration works in unlicensed blocks to minimise financial risks and attract more prospecting companies. In addition the Government was to undertake several additional activities among them making additional funds available for collection and analysis of primary data, reducing the size of blocks and building internal capacity towards risk mitigation to enhance the rate of oil exploration.

### 6. Energy Act, (2006)

One of the policy objectives outlined in Sessional Paper No. 4 of 2004 on Energy was the enactment of an Energy Act, to repeal the Electric Power Act No. 11 of 1997 and the Petroleum Act Cap. 116, and among others, to establish The Energy Regulatory Commission (ERC), with the regulatory mandate for the electricity, downstream petroleum and renewable energy sub-sectors. The Upstream petroleum operations are not covered under this act.

The Energy Act (2006) (No. 12 of 2006) was enacted in December 2006 and became operational in July 2007. The Act transferred the licensing and regulatory mandate for downstream petroleum operations from the Ministry of Energy to ERC while retaining the policy making function with the Ministry. Using the powers in the Act, the Minister, on advice from the ERC, can make a wide range of regulations for the sub-sector.

In addition to ERC, the Act also established the Rural Electrification Authority and the Energy Tribunal to hear and determine appeals on decisions made by ERC.

### 7. The Petroleum (Exploration and Production) Act (Cap 308)

In the past Kenya was viewed as a frontier territory in terms of oil exploration and there was low interest in acquiring blocks. To improve the attractiveness of the country to international oil exploration companies, the Government enacted the Petroleum (Exploration and Production) Act (Cap 308) (The Petroleum Act) in 1984. At the same time the Minister, using the powers under section 6 of the Act issued the Petroleum (Exploration and Production) Regulations (1984) (The Petroleum Regulations) within which the Model Production Sharing Contract (PSC) was embedded.

The Petroleum Act, the Petroleum Regulations and the model PSC have been the basic legal framework for upstream oil and gas operations in Kenya for the last thirty years. The only addition was the gazettment of the Petroleum (Exploration and Production) (Training Fund) Regulations, in 2006.

The main provisions in the Petroleum Act, among others, include:

(i) All petroleum existing in its natural condition in strata lying within Kenya and the continental shelf is vested in the Government,
(ii) All petroleum operations in Kenya may only be conducted by permission of the Minister.
(iii) The Minister may, negotiate, enter into and sign petroleum agreements with a contractor and petroleum agreements
(iv) Contractors are authorized to engage in petroleum operations within specified areas in accordance with the terms and conditions established in a petroleum agreement (a production sharing contract in the form of the Model PSC).
(v) The Minister may also grant non-exclusive exploration permits for the purpose of obtaining geological information.
(vi) The Minister has the supervisory role in the petroleum operations carried out under a petroleum agreement;
(vii) Minister may make regulations in relation to various provisions of the Act.

### 8. The Petroleum (Exploration and Production) Regulations (1984)

The Regulations were gazetted at the same time as the Petroleum Act. They provide the framework of activities which the Minister may undertake towards negotiating and concluding an agreement.

Included in the Regulations are:

(i) The Minister may by notice, declare the opening of blocks for petroleum operations and contractors may make applications for the negotiation of petroleum agreements.
(ii) That a petroleum agreement shall be negotiated on the basis of the model production sharing contract substantially in the form set out in the Schedule.
(iii) Application and Issuance of exploration permits.
(iv) Requirements for access to land.
(v) The requirement for fees and other payments payable under a petroleum agreement or an exploration permit shall which be as determined by the Minister from time to time.
(vi) The detailed Model Production Sharing Contract (PSC) which is attached as a schedule.

## 9. The Model Petroleum Production Sharing Contract (PSC)

The signed PSC is the legal framework which authorises oil exploration companies to engage in petroleum operations within Kenya. It is the full legal relationship between the contractor and the Government in relation to the specific oil exploration block.

In the PSC the specific terms and conditions of the contract are specified in areas such as:

(i) The terms for each exploration period -the initial, first additional and second additional exploration periods as applicable,
(ii) The areas to be surrendered after each exploration period.
(iii) The minimum exploration work and expenditure obligations of each exploration period
(iv) The service fees payable.
(v) The conditions under which the contract may be terminated.
(vi) The rights and obligations of the contractor covering such areas as standard of conduct, liabilities, indemnities, local employment, data, samples and reporting procedures among others.
(vii) The rights and obligations of the Government and the Minister.
(viii) Work programmes during the exploration, development and production phases.
(ix) Cost recovery, production sharing and Government participation.

To operationalise the three documents, there is an agreement between the Ministry and the National Oil Corporation of Kenya ("National Oil"). In the agreement NOCK is mandated to coordinate and facilitate PSC negotiations, and is to carry out financial appraisals of PSCs. In addition there is an inter-ministerial committee, the National Fossil Fuels Advisory Committee ("NAFFAC") composed of the Ministry, NOCK, the Office of the Attorney General, the Kenya Revenue Authority, the National Environmental Management Authority, as well as the Petroleum Institute of East Africa which is involved in negotiating the PSCs.

# Appendix D. - Review of Draft policy and legislation currently under consideration

## 1. Draft National Energy and Petroleum Policy, (20th January 2015 Edition)

The proposed policy sets up the policies and strategies for the energy sector to align them with the Constitution of Kenya, 2010 and Kenya Vision 2030. The process of making the policy started in the year 2011 before oil discoveries were made in Kenya. The draft has undergone several editions and there is evidence that the Government has incorporated some of the recent recommendations by consultants to enhance the policy document. After reviewing the existing policies, laws, regulations and institutional frameworks, the document proposes future policies for the various energy sub sectors and related matters per the following wide thematic areas:

(i) Petroleum and Coal
(ii) Renewable Energy
(iii) Electricity
(iv) Energy Efficiency and Conservation
(v) Land, Environment, Health and Safety
(vi) Devolution and Provision of Energy Services
(vii) Cross cutting issues

Under the section on Petroleum and Coal the draft policy gives detailed policies for the following sub themes:

(i) Upstream Petroleum
(ii) Midstream and Downstream Petroleum
(iii) Midstream and Downstream Natural Gas;
(iv) Coal Resources

The stated overall objective of the energy policy is to ensure affordable, competitive, sustainable and reliable supply of energy to meet national and county development needs at least cost, while protecting and conserving the environment. The Vision is ***"Affordable Quality Energy for all Kenyans"*** and the Mission is ***"To facilitate provision of clean, sustainable, affordable, competitive, reliable and secure energy services at least cost while protecting the environment".***

While the vision in the 2004 Sessional Paper on Energy was equitable access to quality energy services, the proposed draft policy lays emphasis on affordable quality energy. The mission stated in the proposed policy remains broadly similar to the earlier one but has added the word "competitive" to the energy services.

The Draft Policy identifies the challenges facing the upstream, midstream, gas and downstream operations of the petroleum sector in Kenya and then makes policy recommendations to address them.

**Proposed policy and regulatory framework for the upstream oil and gas sector**

The proposed policies for the upstream petroleum and gas subsector cover a wide range of issues ranging from promotion of exploration, production and exploitation operations, legal and institutional changes to resource sharing and governance issues. In the legal framework the draft Energy Policy has proposed separate laws for both upstream and downstream petroleum. This is an improvement over the May 2014 draft which had proposed one law for the two sectors.

The draft policy proposes that the following initiatives regarding the legal, regulatory and institutional frameworks be implemented regarding the upstream subsector:

(i) Revision of both Cap 308 of the Petroleum (Exploration and Production) Act and the model PSC to ensure that it is adequate to support a dynamic, competitive, well managed and modern upstream oil and gas exploration activities to include issues such compensation regime; licensing rounds; community awareness and participation; gas terms; competitive bidding for blocks; environmental protection; conservation and management; and sharing of benefits mechanism between the national and county Government among others.
(ii) Restructure the National Fossil Fuels Advisory Committee ("NAFFAC") to create two advisory committees; one for upstream petroleum operations and another one for coal resources. The role of the proposed National Upstream Petroleum Advisory Committee, which will be anchored in law, will be to advise the Cabinet Secretary on all upstream petroleum exploration and development matters.
(iii) Establish an independent regulatory institution for the upstream petroleum operations.
(iv) Develop a policy on management of commercial discoveries of petroleum resources. This is necessary to provide policy guidance to the Ministry and the relevant institutions.
(v) Develop a legal framework that ensures local content covering technology and knowledge transfer, capacity building of local industry and local employment opportunities in the energy sector.
(vi) Provide a legal and regulatory framework for midstream petroleum and gas infrastructure including third party access at reasonable terms and conditions.
(vii) Restructure and enhance National Oil Corporation of Kenya's ("NOCK") capacity and focus to conduct upstream business. There will be need to clearly define the role of NOCK and the proposed Upstream Petroleum Authority in relation to upstream oil and gas operations.
(viii) Undertake the requisite process leading to making Kenya compliant with the Extractive Industries Transparency Initiative ("EITI")
(ix) Restructure NOCK to separate midstream/downstream business from upstream business with a view to enhancing capacity of the upstream to fully conduct the activities.
(x) Ensure that oil and gas resources are managed in line with the Constitution.
**(xi)** Develop a legal framework that ensures local content covering technology and knowledge transfer, capacity building of local industry and local employment opportunities among others in the energy sector.

**Proposed policy and regulatory framework for downstream and midstream petroleum, and Gas**

Kenya has had a relatively dynamic downstream petroleum sector for many years. While the infrastructure is currently experiencing capacity constraints to meet market demand, plans are already in place to address these for the medium term. The policy recommendations for this sector are mainly related to long term infrastructure improvements.

In regard to the legal and regulatory frameworks, the only recommendations for downstream operations relate to enhancement of the capacity of the existing institutions to regulate the sector in accordance with existing laws and regulations. Some of these policy guidelines are:

(i) Enhance the institutional capacity of the Kenya Bureau of Standards ("KEBS") and ERC to enforce regulations on the quality and standards of petroleum products.
(ii) Enforce compliance with regulations for operational stocks to enhance security of supply of petroleum products
(iii) Enforce compliance with regulations for handling of hazardous and noxious substances

In regards to gas, the draft National Energy and Petroleum Policy recommends the establishment of a legal and regulatory framework to facilitate the development of this potential resource in the country. It also recommends the enhancement of the regulatory powers of the Energy Regulatory Commission to cover midstream petroleum and gas infrastructure including third party access at reasonable terms and conditions to such facilities like pipelines and storage tanks. This is important to ensure optimal use of infrastructure, remove entry barriers and thus enhance competition.

**Proposed policy on other Relevant Issues**

In addition to the policy guidelines along the functional splits for the upstream and downstream petroleum and gas sub-sectors, the draft policy has made recommendations on several other issues related to the petroleum industry. These recommendations mainly relate to the establishment of the necessary legal, regulatory and institutional frameworks covering a wide range of issues such as:

(i) Establishment of a consolidated fund to finance strategic petroleum stocks.
(ii) Local Content development.
(iii) Management of Community expectations
(iv) Resource benefit sharing among the stakeholders

## 2. The Draft Energy Bill, 2015 (20th January 2015 issue)

The proposed Energy Bill, 2015 has been developed based on the policy recommendations in the draft National Energy and Petroleum Policy. It is expected to form the legal framework to meet the requirements of both the Kenya Vision 2030 and the Constitution of Kenya, 2010 in relation to energy. When it is enacted, it will repeal the Energy Act, 2006. It includes downstream petroleum, coal, renewable energy, all forms of electrical energy, and energy efficiency and conservation but excludes upstream petroleum

In the bill, the Energy Regulatory Commission is renamed the Energy Regulatory Authority (ERA). The powers of the authority have been more clearly defined in the setting, reviewing, approving contracts, tariffs and charges for common user petroleum logistic facilities.

The Bill requires the Cabinet Secretary to develop and publish an energy policy every six years and an annual implementation report. The Cabinet Secretary is also expected to develop, publish and review integrated least cost energy development plans.

The new proposed Energy Bill 2015 deals with the regulation of midstream and downstream petroleum operations, coal, renewable energy, electricity, energy conservation and nuclear energy. It differs substantially from the earlier editions in that upstream petroleum operations have been removed and a separate law is recommended for that sector. It also seeks to remedy weaknesses experienced in the operationalization of the Energy Act, 2004 such as giving the ERA powers to set tariffs for common user logistic infrastructure.

The following institutions are proposed in the new bill:

(i) Energy Regulatory Authority (ERA). In addition to the functions assigned to the ERC in the Energy Act, 2006, the proposed ERA is given enhanced mandate to regulate additional midstream petroleum operations.
(ii) Energy and Petroleum Tribunal to hear and determine appeals on the decisions made by ERA.
(iii) Rural Electrification and Renewable Energy Corporation.
(iv) Energy Efficiency and Conservation Agency.
(v) Nuclear Electricity Institute.

**Proposed legal framework for downstream petroleum**

With regard to downstream petroleum operations, the proposed Energy Bill, 2015 has maintained the same functional responsibilities as the Energy Act, 2006. In the draft, the Energy Regulatory Commission has been renamed the Energy Regulatory Authority. ERA retains both the technical and economic regulatory powers for the sub sector excluding upstream petroleum operations

As in all the energy sector functions, the Cabinet Secretary has overall responsibility for policy formulation.

In accordance with section 285(3) he may, from time to time, give directions in writing to the ERC with respect to the policy to be observed and implemented by the ERC, and to further operationalise the law, he has the powers to issue regulations on advice by the ERC, for a wide range of issues.

In the making of the new draft, the opportunity has been taken to address some of the difficulties encountered during the implementation of the Energy Act 2006. For example, despite having the power to set retail prices of petroleum products, ERC encountered legal opposition when trying to set tariffs for pipeline transportation and charges for common used storage facilities. The new bill gives ERA powers to set, review and approve contracts, tariffs and charges for common user petroleum logistics facilities and petroleum products.

The draft Energy Bill has examined the division of functions between the national and county Governments in some way but there is still a possibility of conflicts. While the Fourth Schedule, Part 1, Paragraph 31 of the Constitution specifically provides that the National Government shall handle energy policy including electricity and gas reticulation and energy regulation and Part 2 Paragraph 8 (e) of the same Schedule assigns to the county Governments the role of planning and development of electricity and gas reticulation and energy regulation. Since some of these functions appear duplicated, the Bill has limited the functions of the counties to within their jurisdictions and assigned the national Government the overall function over the country.

### 3. Draft Petroleum Exploration, Development and Production Bill 2015 (20th January 2015 issue)

A new Draft Petroleum Exploration, Development and Production Bill, 2015 and a new Draft Model Production Sharing Contract were published on 20th January 2015. The new draft bill is a major improvement on both the earlier editions and the existing law as the country prepares itself to address the challenges posed by a developing upstream petroleum sector. The object of the proposed bill is to *"to provide a framework for the contracting, exploration, development and production of petroleum; cessation of upstream petroleum operations; to give effect to relevant articles of the Constitution in so far as they apply to upstream petroleum operations; and for connected purposes."*

In its current format the bill proposes wide ranging changes in the legal, regulatory and institutional relationships for the upstream petroleum sector. The bill has addressed the following thematic issues:

(i) Making Policy and Plans;
(ii) Petroleum Institutions;
(iii) Petroleum rights and management of petroleum resources;
(iv) Information and Reporting;
(v) Local Content and Training,
(vi) Payments and Revenues,
(vii) Environment ,Health and Safety,
(viii) Land use for petroleum operations; and
(ix) Other miscellaneous provisions.

The new draft is a major update of The Petroleum (Exploration and Production) Act, Cap 308 and the regulations issued therein to reflect developments in the industry. Most of the policy and regulatory gaps hitherto identified in the draft policy and in our earlier drafts are addressed in the draft.

This draft however has incorporated a major deviation from all the previous policy and legal documents in that it has established a new institution, the Upstream Petroleum Regulatory Authority ("UPRA"), as an independent regulatory authority for upstream operations.

### Functions of the Cabinet Secretary

Under section 10 the draft gives the Cabinet Secretary a wide range of functions including but not limited to:

a) *"make available model petroleum agreements as a basis for the negotiation of petroleum agreements;*
b) *cause any investigations, due diligence or consultations to be made or carried out as considered necessary before entering into a petroleum agreement and may upon advise from the Advisory Committee reject any application made by a potential contractor if satisfied that it is in the best interest of the country;*
c) *upon advise of the Advisory Committee, negotiate, sign or revoke petroleum agreements or appoint an authorized representative to do so in writing on behalf of the Government as provided for in this Act, the regulations made in relation thereto and the petroleum agreement;*
d) *supervise upstream petroleum operations carried out under a petroleum agreement;*
e) *develop, publish and review upstream petroleum policy and strategic plans;*
f) *review and approve any proposed exploration activity contained in the annual work programme, appraisal programme and production forecasts submitted by a contractor;*
g) *review and approve budgets submitted by a contractor;*
h) *upon advise of the Advisory Committee, suspend, revoke or terminate the petroleum agreement or recall the security therein on behalf of the Government as provided for under this Act, the regulations made thereunder and the petroleum agreement;"*

### National Upstream Petroleum Advisory Committee

A new inter-ministerial committee, National Upstream Petroleum Advisory Committee, has been established under section 13 of the draft bill to take up the functions of the previous NAFFAC in regard to upstream petroleum operations. The function of the Advisory Committee shall be to:

a) *"advise the Cabinet Secretary on upstream petroleum operations;*
b) *participate and advise the Cabinet Secretary in the negotiation of petroleum agreements and in the granting and revocation of licences;*
c) *advise the Cabinet Secretary on the suspension, revocation or termination of the petroleum agreement or the recall of security for compliance;*
d) *submit a report to the Cabinet Secretary on the terms negotiated with contractors;*
e) *develop the criteria for negotiation of petroleum agreements;*
f) *participate in the evaluation of the bids and applications for awarding of upstream petroleum blocks;*
g) *perform such other functions and duties as may be provided under this Act or as may be delegated by the Cabinet Secretary."*

### Upstream Petroleum Regulatory Authority

Section 15 of the new draft establishes the Upstream Petroleum Regulatory Authority ("UPRA") as a technical, economic and legal regulator for the upstream petroleum operations. The broad objectives and function of the Authority shall be to:

a) *"regulate upstream petroleum operations in Kenya;*
b) *provide such information and statistics to the Cabinet Secretary as may be required from time to time;*
c) *collect, maintain and manage upstream petroleum data;*
d) *conduct all due diligence and investigate all the affairs of contractors prior to entering into petroleum agreements and make recommendations to the Cabinet Secretary;*

e) *perform any other function that is incidental or consequential to its functions under this Act or any other written law."*

To undertake its functions under the proposed bill, UPRA has been given powers to undertake a wide range of functions covering the upstream petroleum operations. Such powers include the power to:

a) *"coordinate the development of upstream petroleum infrastructure and promote capacity building in upstream petroleum operations;*
b) *monitor and regulate upstream petroleum operations including reserve estimation, measurement and evaluation of the produced oil and/or gas;*
c) *assess field development plans and make recommendations to the Cabinet Secretary for approval, amendment or rejection of the plans;*
d) *assess tail-end production and cessation of upstream petroleum operations and decommissioning;*
e) *verify the measurement of petroleum to allow for estimation and assessment of royalty and profit oil and/or gas due to the Government as well as issue the requisite approvals;*
f) *verify the recoverable cost oil and/or gas due to the parties in a petroleum agreement;*
g) *audit contractors for cost recovery;*
h) *monitor upstream petroleum operations and carry out necessary inspections and audits related to the operations.*
i) *ensure that contractors uphold the relevant laws, regulations and petroleum agreement terms;*
j) *ensure optimal levels of recovery of petroleum resources;*
k) *promote well planned, executed and cost-efficient operations;*
l) *ensure optimal utilization of existing and planned facilities;*
m) *ensure the establishment of a central database of persons involved in upstream petroleum operations;*
n) *manage upstream petroleum data and provide periodic updates and publication of the status of upstream petroleum operations;*
o) *take such action as is necessary to enforce the requirements in a petroleum agreement or any regulations and to protect the health and safety of workers and the public;*
p) *ensure and facilitate competition, access and utilization of facilities by third parties;*
q) *monitor conditions of Operators and their trade practices to ensure that competition and fair practice is maintained;*
r) *provide information to the relevant authority for the collection of taxes and fees from upstream petroleum operations*
s) *set, review and approve contracts, tariffs and charges for common user upstream petroleum logistics facilities;*
t) *make proposals to the Cabinet Secretary, of regulations which may be necessary or expedient for the regulation of the upstream petroleum sector or for carrying out the objects and purposes of this Act;*
u) *work in coordination with the relevant statutory authorities to formulate, enforce and review environmental, health, safety and quality standards for the upstream petroleum sector;*
v) *prescribe the form and manner in which any application for any authority, consent or approval under this Act shall be made;*
w) *investigate and determine complaints or disputes arising from upstream petroleum operations;*
x) *enter, inspect and search any premises at which any undertaking is carried out or an offence under this Act is being committed or is suspected to have been committed;*
y) *issue orders either verbally or in writing requiring acts or things to be performed or done, prohibiting acts or things from being performed or done, and may prescribe periods or dates upon, within or before which such acts or things shall be performed or done or such conditions shall be fulfilled;*
z) *develop guidelines on ratified or ascended treaties, conventions and protocols affecting the upstream petroleum sector in consultation with other statutory authorities;*

*aa) impose such sanctions and civil fines, being not less than ten thousand shillings per violation per day, as may be prescribed in regulations to secure compliance with orders issued under this Act;*
*bb) prosecute offences created under this Act;*
*cc) regulation of contracts on upstream petroleum operations not specifically provided for under this Act;*
*dd) monitor and enforce local content requirements;*
*ee) issue operational permits and non-exclusive operational permits in accordance with this Act;*
*ff) ensure enforcement and compliance with the National Transparency and Accountability Standards; and*
*gg) perform any other function incidental or consequential to its functions under this Act."*

Section 130 (3) of the draft bill provides that the powers and functions of UPRA under the Act shall in the interim period before the Authority is operationalized be exercised by the Energy Regulatory Commission established under section 4 of the Energy Act, 2006. In addition section 130 (4) provides that he Cabinet Secretary shall at an appropriate time operationalize the Authority through a notice in the Kenya Gazette.

### 4. Draft Model Production Sharing Contract (11th October 2014 issue)

A revised draft Model Production Sharing Contract (PSC) has also been issued together with the Draft Petroleum Exploration, Development and Production Bill. The new draft PSC now includes additional issues which were not in the existing PSC and also gives more details on some of the issues in the previous document.

In addition to setting out the legal relationships between the Government and the upstream petroleum licencees, the draft PSC captures and gives more details in such issues as:

(i) Local Content
(ii) Environment, Health and Safety issue ;
(iii) Natural Gas;
(iv) Profit sharing formula;
(v) Domestic sharing mechanism including gas;
(vi) Accounting procedures and cost classifications.

### 5. Draft Petroleum Exploration, Development and Production (Local Content) Regulations (11th October 2014 edition)

Together with the draft policy and the two draft bills, draft regulations were issued on local content. This Draft Petroleum Exploration, Development and Production (Local Content) Regulations is the first edition of these proposals. In the draft, local content is defined as the "*quantum or percentage of locally produced materials, personnel, financing, goods and services rendered in the petroleum industry value chain and which can be measured in monetary terms.*"

This draft requires further work to ensure that is meets the expectations of all stakeholders. So far there has been no stakeholder forum to open the subject to a wider debate and participation.

The requirements for local content per the draft are too prescriptive e.g. during the procurement processes for an upstream petroleum industry which is just starting to take off. This could result in costly delays in undertaking contractual work programmes. For example under section 21, contractors are expected to have researched plans and budgets before commencement of petroleum operations. Some of the target local content requirements may also be difficulty to achieve in the initial stages.

***It is recommended that a local content policy, be developed with full stakeholder participation, before any regulations on this issue.***

**Impacts of New proposals in the new draft Petroleum Exploration, Development and Production Bill**

The establishment of the UPRA is a major step in separating the role of the Ministry of Energy and Petroleum by setting up an independent regulator. The ministry will be left with policy, approvals of agreements and overall supervision of the sub sector while UPRA will be responsible for operational and regulatory matters. This is in keeping with the historical developments in the benchmarked countries. UPRA will also to some extent help shield upstream exploration companies from being exploited by local communities, as UPRA will be the face of exploration.

***There is a likely conflict of roles in the powers of permitting of petroleum operations as Clause 8 (1) seems to give these powers to both the Cabinet Secretary and UPRA.***

# Appendix E. - Oil and gas supply

## Prospectivity of Licencing Blocks in Kenya

A summary of supply prospectivity based on publicly available information for is provided for each block in the table below as at around mid-2014.

*Table E - 1: Prospectivity of licencing blocks in Kenya*

| Basin | Block | Company | Wells | Activity | Prospectivity |
|---|---|---|---|---|---|
| **Lamu Embayment** | 2A | Simba Petroleum | • None drilled<br>• No firm plans | • Airborne Survey | • Too early, but initial survey suggests could have 2 prospects.<br>• Oil Seeps<br>• Tarbaj-1 well |
| **Lamu Embayment** | 2B | Lion Petroleum (Taipan Resources) | Badada 1 well due to spud end 2014, early 2015. Target mean unrisked resources of 251 mmboe | • Drilling | • Taipan Resources: 1.593 billion boe – 19 exploration leads |
| **North Central Gregory Rift** | 10BB | Africa Oil | Dyepa-1 (South Kerio basin) well to spud 14'Q2, and then Aze prospect in North Kerio basin. Ekunyuk-1 well [??] | • Should be drilling<br>• Ekunyuk-1 well drilled [May 14] – oil discovery<br>• Seismic being shot | • 7 discoveries, including: Amosing-1, Ewol-1, Ngamia-1, Etuko-1 (all oil)<br>• Number of prospects identified |
| **North Central Gregory Rift** | 10BB | Tullow | 7 discoveries out of 7 wells: Amosing-1, Ewoi-1, Etuko-1, Emong-1, Ngamia, Twiga South-2 | • Tullow and partners proceeding to development studies, pre-FEED export pipeline, targeting project sanction in 2015/16 | • Amosing-1, Ewoi-1, Ekales-1, and Agete-1:<br>• Estimate resources > 600mmbo with potential to exceed 1 billion boe |
| **North Central Gregory Rift** | 10BA | Africa Oil | Engomo [formerly Kiboko] prospect on Lake Turkana | • Drilling and planning to drill | • Number of prospects identified |
| **Lamu Embayment** | 9 | Africa Oil | Drilling Sala-1 exploration well, testing a large prospect on NE flank of Cretaceous Anza rift (updip of 2 wells (Bogal-1 & Ndovu-1) with | • Drilling – Sala-1 gas discovered. Tested dry gas at a maximum rate of 6 mmcf/d from a | • The gross best estimate of prospective resources are 1.8 trillion cubic feet. |

| Basin | Block | Company | Wells | Activity | Prospectivity |
|---|---|---|---|---|---|
| | | | hydrocarbon shows – results expected June.) | 25 meter net pay interval.<br>• An appraisal plan<br>• currently being evaluated with GoK | |
| **Lamu Embayment** | 10A | Africa Oil | Cancelled plans to drill | • Not continuing into next exploration phase | |
| **North Central Gregory Rift** | 13T | Africa Oil | Drilling at Twiga South-2 being drilled, discovery Twiga South-1 well was sidetracked and tested 62 meters of vertical oil pay<br>Agete-1 well is being tested | • Drilling and collecting seismic | • Emong-1 – oil & gas shows,<br>• Ekales-1 significant oil discovery |
| **North Central Gregory Rift** | 13T | Tullow | Ngamia-1 discovered oil<br>Emong-1 – poor reservoir sands<br>Twiga South-2 well is drilling up dip of Twiga South-1<br>Ngamia-2 well to be drilled to appraise discovery<br>Agete-1 to be tested. | • | • Material oil discovery at Ngamia-1<br>• Etuko & Ewoi<br>• Amosing discovery may be one of the largest discoveries in the basin to date.<br>• Etuko was tested but flowed water with oil shows.<br>• Ekales-1 flowed 1000 bbl/d |
| **North Central Gregory Rift** | 12A | Africa Oil | | • Seismic acquired | |
| **Lamu Embayment – Coastal** | L4 & L13 | Zarara / Sohi Gas | | • Acquiring seismic<br>• Planning Pate-2 well which will be completed as a producer – long term test of around 10 mmscfd with gas supplied to local electricity generation | • Contains Pete gas prospect (drilled by BP/Shell in 1970 – over-pressured – blowout)<br>• GIIP 950bcf<br>• Remaining 667 bcf – P50 |

| Basin | Block | Company | Wells | Activity | Prospectivity |
|---|---|---|---|---|---|
| | | | | • Longer term 60 mmscfd supplied to power generation | |
| **Lamu Embayment – Coastal** | L6 | Flow Energy / Ophir Energy | | • Drilling depends on FAR achieving a farm out | • 3 prospects – unrisked<br>• Tembo: 327 mmbo or 807 bcf<br>• Kifaru: 178 mmbo or 517 bcf<br>• Kifaru Wst:130mmbo or388 bcf |
| **Lamu Embayment – offshore deep water** | L9 | Flow Energy / Origin Energy | Simba-1 well drilled 1979 – gas shows | • 3D seismic acquired, further seismic to be sought | |
| **Lamu Embayment – offshore deep water** | L10A | BG/ Pancontinent al /PTTEP | Sunbird-1 drilled, hydrocarbons discovered, no further info | • Evaluating well results | • Sunbird-1 discovered hydrocarbons |

*Source: PwC Consortium*

## *High Case Resource estimates and Supply profiles*

*Table E- 2: High case resource estimate*

| Basin | Type of Hydrocarbons | Estimated Resource in Place | Assumed Recovery Factor | Recoverable Reserves (bbl/boe*) | First Production |
|---|---|---|---|---|---|
| **East African Rift** | Oil | 6 billion bbl | 40% | 2,400,000,000 | 2018 |
| **Anza Graben (oil)** | Oil | 4.5 Billion bbl | 40% | 1,800,000,000 | 2019 |
| **Anza Graben (gas)** | Gas | 4.0 Tcf (666 million boe) | 80% | 532,800,000 | 2020 |
| **Coastal Lamu** | Gas | 30 Tcf (5 billion boe) | 80% | 4,000,000,000 | 2020 |
| **Offshore** | Gas | 4.5 Tcf (750 million boe) | 80% | 600,000,000 | 2020 |

*Boe – Barrel of Oil Equivalent

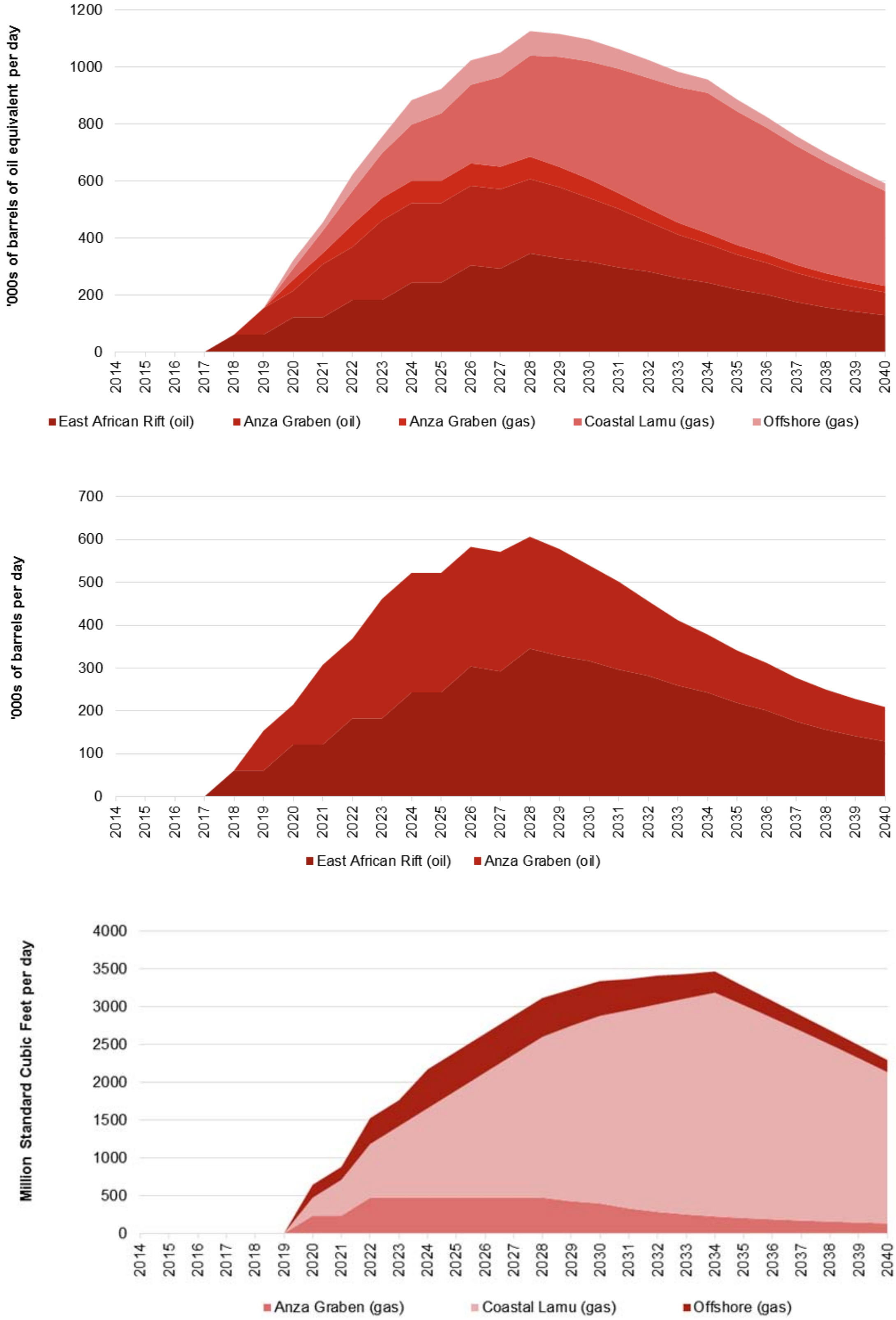
*Source: PwC Consortium*

*Table E - 3: High case reserves development assumptions*

| Basin | Developments | Timing |
|---|---|---|
| **East African Rift** | 6 x 1 billion bbl oil field | 1 per alternate year after 1st |
| **Anza Graben (oil)** | 3 x 1.5 billion bbl oil field | 1 per alternate year after 1st |
| **Anza Graben (gas)** | 2 x 2 tcf gas field | 2nd starts in 3rd year |
| **Coastal Lamu** | 15 x 2 tcf gas field | 1 per year after 1st |
| **Offshore** | 3 x 1.5 tcf gas field | 1 per alternate year after 1st |

*Source: PwC Consortium*

*Figure E - 1: High case oil and gas supply profiles*




*Source: PwC Consortium*

*Table E -4: High case oil and gas profiles*

| HIGH CASE | East African Rift (oil) | Anza Graben (oil) | Total Oil | Anza Graben (gas) | Coastal Lamu (gas) | Offshore (gas) | Total Gas |
|---|---|---|---|---|---|---|---|
| | BBL/d | BBL/d | BBL/d | MMScfd | MMScfd | MMScfd | MMScfd |
| **2018** | 60,800 | | **60,800** | | | | **60,800** |
| **2019** | 60,800 | 93,000 | **153,800** | | | | **153,800** |
| **2020** | 121,600 | 93,000 | **214,600** | 236 | 236 | 172 | **644** |
| **2021** | 121,600 | 186,000 | **307,600** | 236 | 473 | 172 | **881** |
| **2022** | 182,400 | 186,000 | **368,400** | 473 | 709 | 343 | **1,525** |
| **2023** | 182,400 | 279,000 | **461,400** | 473 | 946 | 343 | **1,762** |
| **2024** | 243,200 | 279,000 | **522,200** | 473 | 1,182 | 515 | **2,170** |
| **2025** | 243,200 | 279,000 | **522,200** | 473 | 1,418 | 515 | **2,406** |
| **2026** | 304,000 | 279,000 | **583,000** | 473 | 1,655 | 515 | **2,642** |
| **2027** | 292,400 | 279,000 | **571,400** | 473 | 1,891 | 515 | **2,879** |
| **2028** | 345,500 | 261,200 | **606,700** | 473 | 2,128 | 515 | **3,115** |
| **2029** | 328,500 | 249,500 | **578,000** | 427 | 2,318 | 482 | **3,227** |
| **2030** | 316,700 | 223,400 | **540,100** | 398 | 2,480 | 460 | **3,338** |
| **2031** | 296,500 | 205,400 | **501,900** | 331 | 2,620 | 412 | **3,364** |
| **2032** | 282,000 | 174,400 | **456,400** | 286 | 2,744 | 379 | **3,409** |
| **2033** | 259,500 | 152,300 | **411,800** | 252 | 2,856 | 322 | **3,430** |
| **2034** | 243,100 | 135,600 | **378,700** | 226 | 2,957 | 281 | **3,464** |
| **2035** | 218,900 | 122,300 | **341,200** | 204 | 2,813 | 250 | **3,268** |
| **2036** | 201,000 | 111,200 | **312,200** | 187 | 2,662 | 226 | **3,075** |
| **2037** | 175,400 | 101,900 | **277,300** | 171 | 2,504 | 205 | **2,881** |
| **2038** | 156,300 | 93,700 | **250,000** | 158 | 2,341 | 188 | **2,687** |
| **2039** | 141,300 | 86,700 | **228,000** | 146 | 2,171 | 173 | **2,491** |
| **2040** | 128,900 | 80,300 | **209,200** | 135 | 1,997 | 160 | **2,293** |

*Source: PwC Consortium*

# Appendix F. - Demand Outlook – Petroleum

## Introduction

The twenty five year forecast of Liquid Fuels to the year 2040 for Kenya requires an identification of the principal drivers of socio/economic growth over the next two and a half decades. These will comprise global as well as domestic trends. Crude oil and petroleum products are internationally traded commodities in fluid markets that operate in a full twenty four hour cycle. Prices are decided by world supply and demand, and factors mostly exogenous to the Kenyan economy will determine them. Essentially the Kenyan economy will be a price taker of crude oil and petroleum product prices even if it establishes significant crude oil reserves of its own, as in terms of its Vision 2030, the country endeavours to create a globally competitive and prosperous country providing a better quality of life for all its citizens. This will require an open economy that engages in international trade and participates in international markets.

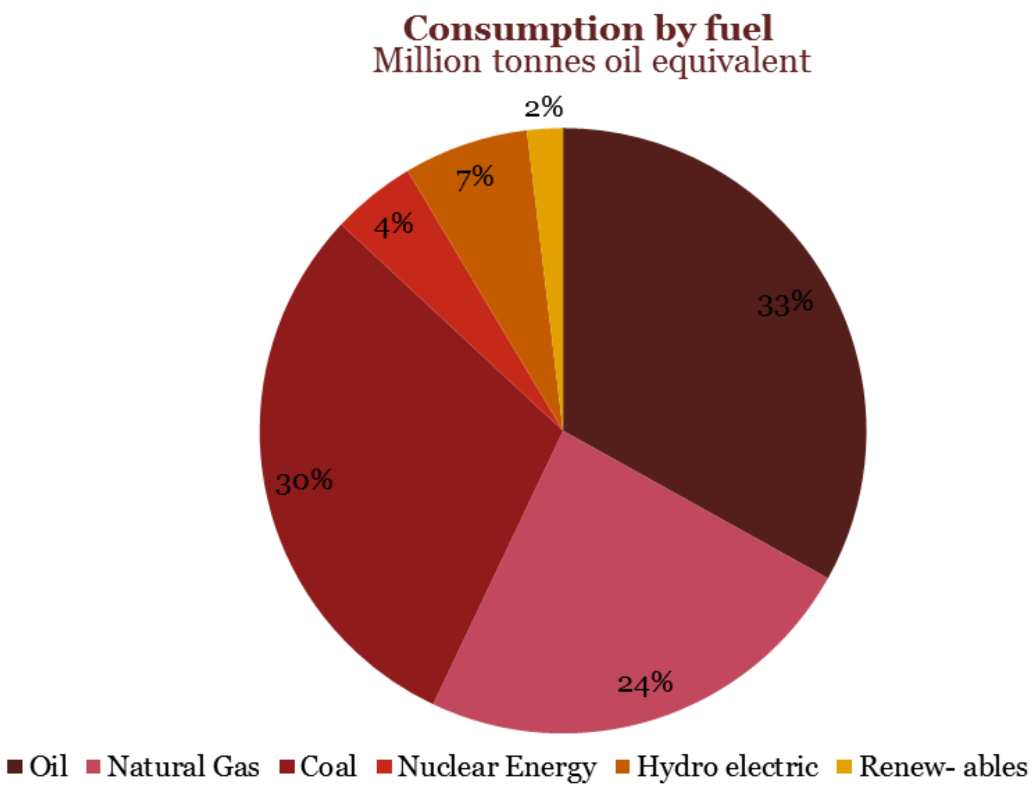
Domestically, Liquid Fuels demand is influenced by the level of economic activity and the efficiency or productivity of that activity. Economic activity is driven by urbanisation and population growth as people move out of the rural areas to the cities and seek higher paid work and also a greater share of the material benefits available. Urbanisation increases productivity by freeing people from low productivity activities such as subsistence agriculture and informal trading and creates the opportunity to enhance skills which further increases productivity. There are a significant number of Kenyans trapped in small scale agriculture or subsistence farming and pastoralist activities, as described by the Kenya National Bureau of Statistics (2014:65), who, if released to more productive economic activities, could substantially improve economic output as well as their own welfare.

Transport is the biggest consumer of refined petroleum products. Petroleum product demand is driven by infrastructure development and growth in vehicle usage. Kenya is a large country of 580,367 square kilometres and is slightly bigger than France. The country is a conduit for landlocked states to the West and North of the country such as Uganda, Rwanda, Burundi, South Sudan and Ethiopia and trade is important as evidenced by the proposed large investment in the Lamu Port South Sudan Ethiopia transport corridor (LAPSSET). This means that logistics play a key role in the economy and that the Kenyan market extends beyond the 43.2 million people of Kenya to the 193.5 million people of these landlocked countries (World Bank, 2012). Transportation is almost totally reliant on liquid fuels and this drives refined petroleum product demand. Technology advances will play a key role in this sector in helping to curb demand in the future, particularly for petrol, as fuel efficiency continues to improve.

This section studies the demand for the primary refined petroleum products for Kenya to the year 2040. The products include petrol, diesel, jet fuel and illuminating kerosene, Liquid Petroleum Gas (LPG), and fuel oil. Of these six the first five, petrol, diesel, jet, illuminating kerosene and LPG are light and middle distillate fuels, and command higher prices than fuel oil, and the demand for these petroleum products is greater than for fuel oil. Petrol, diesel and jet are used primarily in the transportation sector, where there are almost no substitutes, and as such they are essential to a modern economy.

Oil and natural gas are the world's most widely used fuels. In 2012, they produced 57 per cent of the world's energy as shown in the figure below. Energy is fundamental as it facilitates movement which is essential to modern human life.

*Figure F – 1: Use of energy carrier 2012*




*Source: BP Statistical Review, 2013*

The growth in renewables such as bio-diesel and ethanol is expected to increase worldwide over the forecast period; however conventional oil will remain the substantive energy carrier in the transport sector.

We will set the scene for the global oil and economic markets before focusing in on Kenya's growth prospects. We will then outline the forecasts for liquid fuel volumes for each of the major refined products.

## Supply and Demand in the Global Oil Market

Crude oil and refined petroleum products have been the dominant global energy carriers over the past century.

The world oil market is changing. The demand for oil is moving from the Organization of Economic Co-operation and Development (OECD) or Advanced Economies to the Non-OECD or Emerging and Developing Economies. Starting from 2013 onwards more oil is being consumed outside the OECD than within the OECD and the gap will continue to grow. As energy is used more efficiently, global energy consumption is expected to rise more slowly over the period 2015 to 2040 than the previous 25 years. Most of that growth in demand is expected to come from the emerging economies, while energy use in the advanced economies of North America, Europe and Asia (considered here as a group) is expected to grow only very slowly – and begin to decline in the later years of the forecast period.

The table below shows how oil consumption in the OECD has fallen from 2115.8 million tons in 2010 to 2059.9 million tons in 2013 (2.6%), while European Union consumption fell by 55.7 million tons over the same period (9.2%). Non-OECD consumption on the other hand rose by 200.7 million tons, or 9.4% over the same period. Russian and Chinese consumption grew by 14.0% and 15.2% respectively.

Africa is seen as the latest demand frontier and the table below shows Africa as the region with the second highest global growth of all the regions in 2012 over 2011.

This is shown at 3.2% and excluding South Africa at 3.6%, behind South and Central America at 4.4%.

*Table F – 1: Global oil consumption – 2010 to 2012*

Canada, European Union & OECD consumption has decreased

| **Oil: Consumption*** | | | | | **Change** | **2013** |
|---|---|---|---|---|---|---|
| | | | | | 2013 over | Share |
| **Million tonnes** | 2010 | 2011 | 2012 | **2013** | 2012 | of total |
| | | | | | | |
| **US** | 850.1 | 834.9 | 817.0 | **831.0** | 2.0% | 19.9% |
| **Canada** | 101.3 | 105.0 | 104.3 | **103.5** | -0.5% | 2.5% |
| **Mexico** | 88.5 | 90.3 | 92.3 | **89.7** | -2.6% | 2.1% |
| **Total North America** | **1039.9** | **1030.2** | **1013.6** | **1024.2** | **1.3%** | **24.5%** |
| **Total S. & Cent. America** | **283.2** | **290.5** | **299.2** | **311.6** | **4.4%** | **7.4%** |
| **Russian Federation** | 134.3 | 143.5 | 148.9 | **153.1** | 3.1% | 3.7% |
| **Total Europe & Eurasia** | **906.4** | **902.3** | **884.2** | **878.6** | **-0.4%** | **21.0%** |
| **Saudi Arabia** | 124.2 | 125.1 | 131.3 | **135.0** | 3.1% | 3.2% |
| **Total Middle East** | **354.3** | **361.3** | **377.7** | **384.8** | **2.2%** | **9.2%** |
| **Total Africa** | **164.3** | **158.5** | **166.1** | **170.9** | **3.2%** | **4.1%** |
| **China** | 440.4 | 464.1 | 490.1 | **507.4** | 3.8% | 12.1% |
| **Total Asia Pacific** | **1292.0** | **1342.3** | **1398.1** | **1415.0** | **1.5%** | **33.8%** |
| | | | | | | |
| **of which: OECD** | 2115.8 | 2093.3 | 2072.9 | **2059.9** | -0.4% | 49.2% |
| **Non-OECD** | 1924.4 | 1991.8 | 2066.0 | **2125.1** | 3.1% | 50.8% |
| **European Union** | 660.9 | 643.1 | 618.8 | **605.2** | -1.9% | 14.5% |
| **Former Soviet Union** | 186.2 | 200.7 | 206.9 | **212.2** | 2.8% | 5.1% |

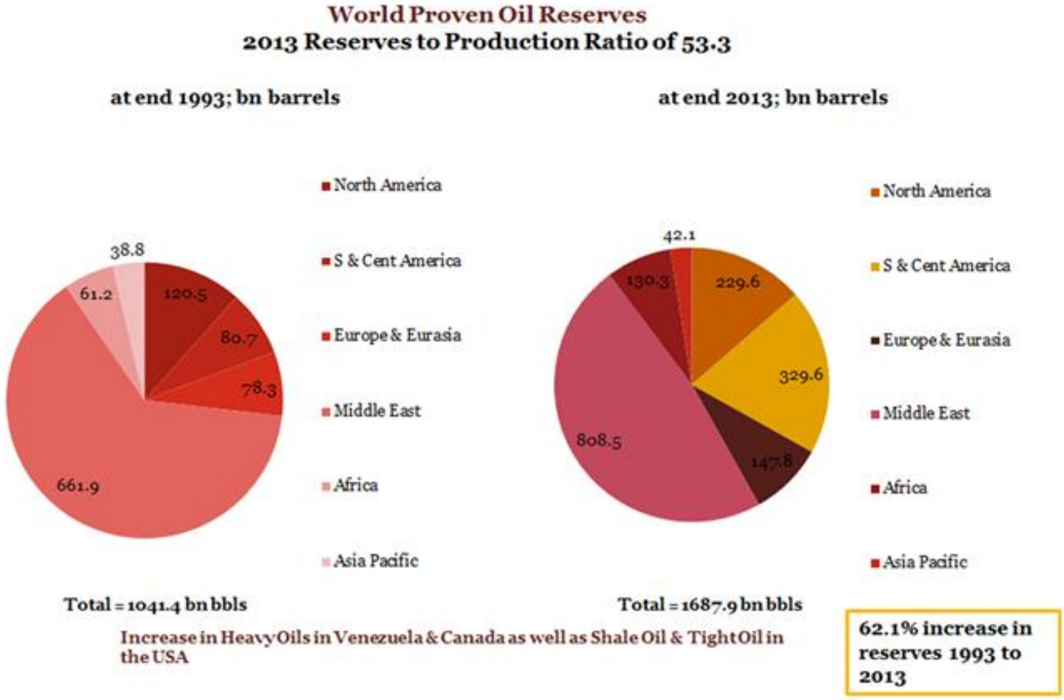
*** Inland Demand plus international aviation and marine bunkers and refinery fuel and loss. Consumption of biogasoline (such as ethanol), biodiesel and derivatives of coal and natural gas are also included.**

**Growth rates are also adjusted for leap years.**

*Source: BP Statistics 2014*

World oil supply is also changing. As highlighted in the figure below North American proven oil reserves have increased. The exploitation of shale oil and tight oil within the USA could see the country as a net exporter of oil and natural gas in the next decade (beyond 2020). This would be a substantial shift from this country's historic reliance on imported crude oil from the Middle East, Latin America and West Africa. As the biggest economy in the world at US$ 15 684b in 2012 or 21.8% of the world GDP, and in 2010 consuming two and a half times more than the nation produced, this relative self-sufficiency will make a significant difference to the world supply/demand balance of oil.

*Figure F – 2: Global oil reserves – 1993 & 2013*




*Source: BP Statistics, 2014*

Proven reserves are still concentrated in the Middle East, however the demand from this region by the OECD will reduce in the future (2015 and beyond). The emerging economies, particularly in Asia, are expected to draw from this region.

*Table F - 2: Global oil manufacture–2010-2012*

| **Oil: Production *** | | | | | **Change** | **2013** |
|---|---|---|---|---|---|---|
| | | | | | 2013 over | Share |
| **Million tonnes** | 2010 | 2011 | 2012 | **2013** | 2012 | of total |
| | | | | | | |
| **US** | 332.9 | 345.7 | 394.1 | **446.2** | 13.5% | 10.8% |
| **Canada** | 160.3 | 169.8 | 182.6 | **193.0** | 6.0% | 4.7% |
| **Mexico** | 145.6 | 144.5 | 143.9 | **141.8** | -1.1% | 3.4% |
| **Total North America** | **638.8** | **660.0** | **720.6** | **781.1** | **8.7%** | **18.9%** |
| **Total S. & Cent. America** | **377.8** | **381.7** | **374.7** | **374.4** | **0.2%** | **9.1%** |
| **Russian Federation** | 511.8 | 518.5 | 526.2 | **531.4** | 1.3% | 12.9% |
| **Total Europe & Eurasia** | **861.1** | **846.2** | **837.7** | **837.5** | **0.3%** | **20.3%** |
| **Saudi Arabia** | 473.8 | 526.0 | 549.8 | **542.3** | -1.1% | 13.1% |
| **Total Middle East** | **1217.1** | **1320.6** | **1342.1** | **1329.3** | **-0.7%** | **32.2%** |
| **Total Africa** | **482.7** | **407.9** | **445.0** | **418.6** | **-5.7%** | **10.1%** |
| **China** | 203.0 | 202.9 | 207.5 | **208.1** | 0.6% | 5.0% |
| **Total Asia Pacific** | **401.7** | **394.3** | **399.8** | **392.0** | **-1.7%** | **9.5%** |
| | | | | | | |
| | | | | | | |
| **of which: OECD** | 857.0 | 858.1 | 903.1 | **951.0** | 5.6% | 23.0% |
| **Non-OECD** | 3122.2 | 3152.5 | 3216.7 | **3181.9** | -0.8% | 77.0% |
| **OPEC** | 1667.2 | 1704.4 | 1776.3 | **1740.1** | -1.8% | 42.1% |
| **Non-OPEC £** | 1647.2 | 1639.6 | 1670.3 | **1711.6** | 2.7% | 41.4% |
| **European Union** | 93.4 | 81.6 | 72.9 | **68.4** | -5.8% | 1.7% |
| **Former Soviet Union** | 664.8 | 666.7 | 673.1 | **681.3** | 1.5% | 16.5% |

***Includes crude oil, tight oil, oil sands and NGLs (the liquid content of natural gas where this is recovered separately).**
***Excludes liquid fuels from other sources such as biomass and derivatives of coal and natural gas.**

**Note: Growth rates are adjusted for leap years**

USA & Canadian production has increased sharply

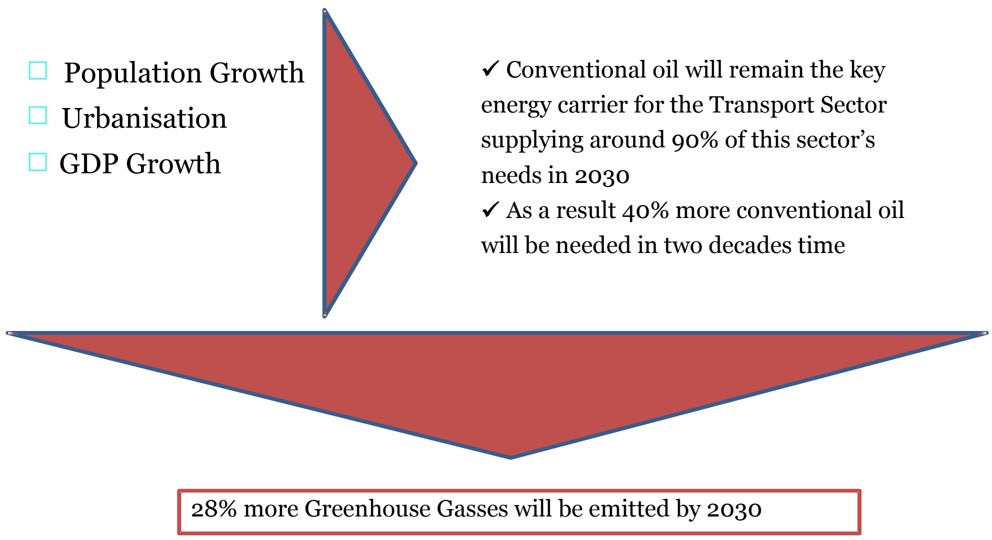
*Source: BP Statistics 2014*

USA oil production has increased significantly since 2010 as the exploitation of tight oil and shale oil has progressed. This is changing the country's economy as well as foreign policy, and is enabling the OECD, or advanced economies as a whole, to show the highest increase in oil production in 2013 over 2012 of all the global regions in the table above. The Russian Federation and Saudi Arabia are the top world oil producers although Russia has significantly lower reserves.

Transport is expected to remain the key sector driving the consumption of oil in the forecast period and oil will remain the key energy carrier for this sector supplying 90% of this industry's needs in 2040. Factored into this forecast are increasing efficiencies in the internal combustion engine which will reduce the consumption of petrol in particular. Natural gas could make a significant contribution as a transport fuel, as it has moved its share of road transport consumption from 0.2% in 2000 to 1.4% in 2010. Technology is already at hand for natural gas propulsion in the road transport sector, but problems remain in the use of this fuel, which include the need for a substantial infrastructure build-up.

*Figure F – 3: Trends in oil demand*

**Key Factors in Future Global Oil Demand**



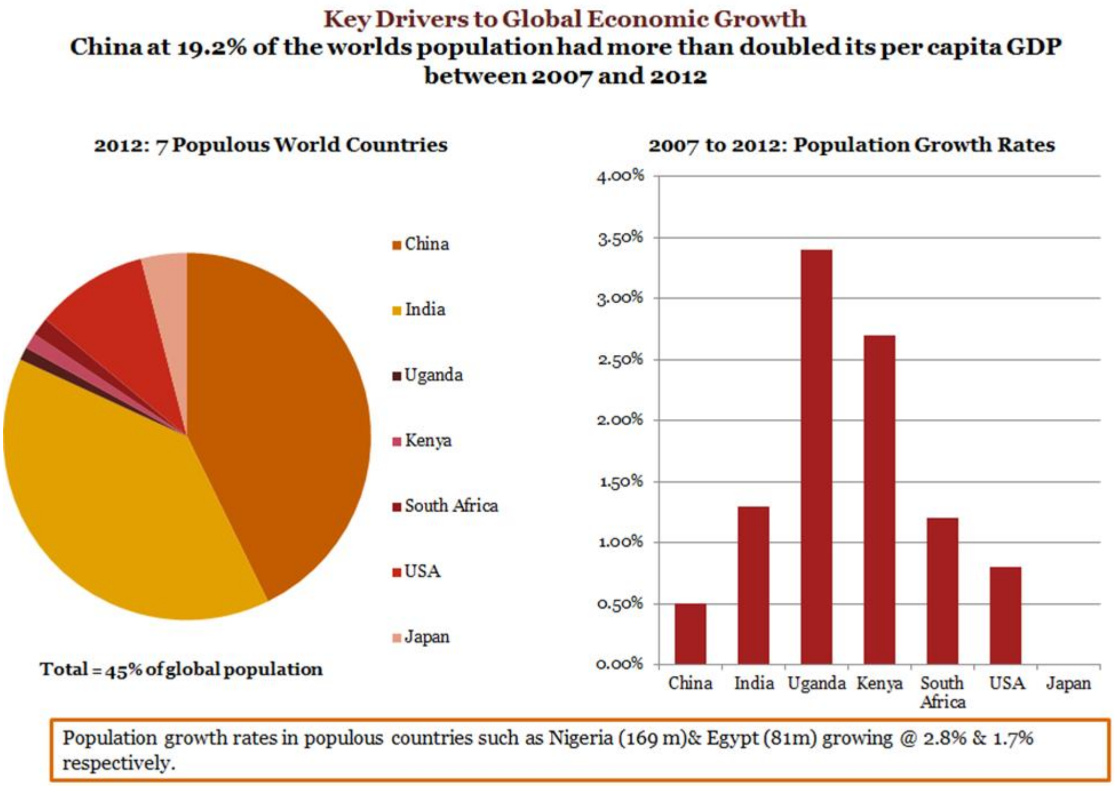

*Source: PwC Consortium*

Few countries produce enough petroleum to satisfy their own demand. Most nations have to import oil for their economies to function. The result of this is that crude oil is the world's most prolifically traded commodity. The demand for petroleum is also price inelastic. Changes in the price of oil do not have a great effect on the volume consumed, in the short to medium term, as customers cannot easily switch between energy carriers. This ensures that crude oil remains a strategic commodity and that it is not left in the hands of the oil companies but is usually kept within the ambit of Government.

## Global Economic Growth

Global growth trends are changing. It is likely that the combined GDP of the non-OECD countries will exceed that of the OECD countries by around 2015. By 2040 the non-OECD GDP could be double that of the OECD countries. The key drivers of economic growth are the effective combinations of the factors of production of land, labour and capital. Urbanization brings the factor of production labour closer to capital and away from low productivity pursuits such as subsistence farming. Productivity increases as labour acquires a higher level of skills which increases consumer demand. This increased demand leads to a virtuous circle of higher income and aggregate demand which ultimately ends in an increased GDP. The key is the productivity of labour and how technology, capital and skills are harnessed to boost that productivity.

*Figure F – 4: The factor of production - Labour*



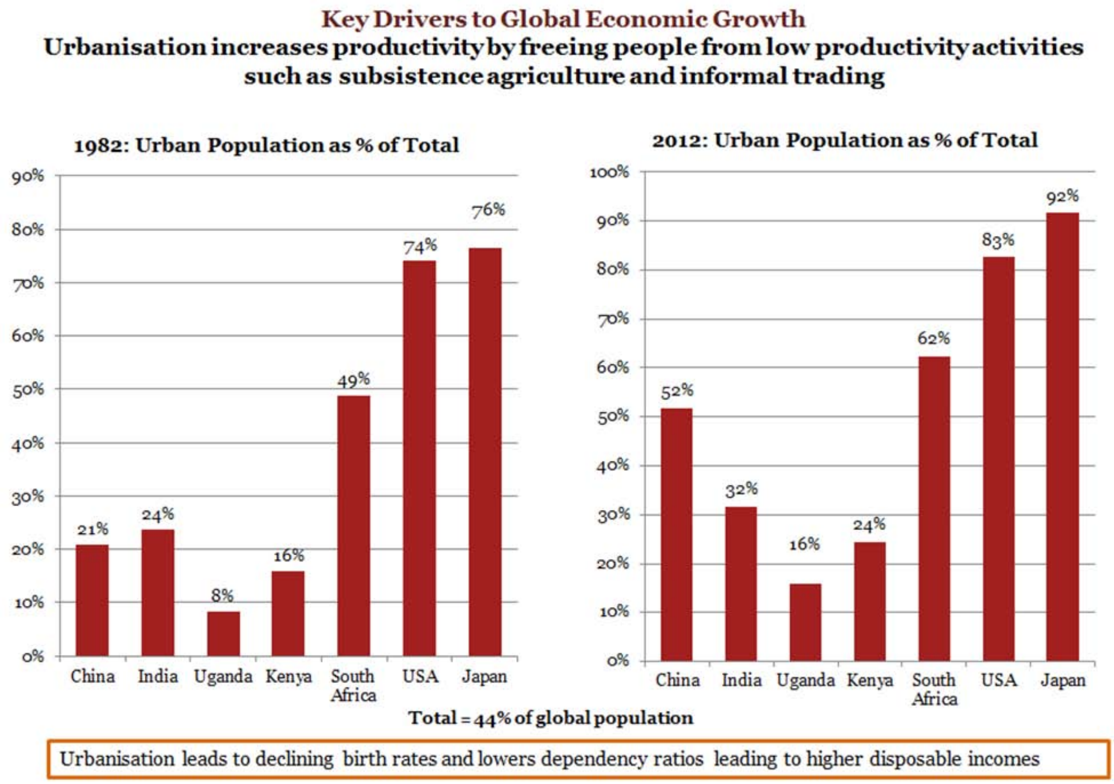

*Source: World Bank, World Development Indicators, 2013*

The example of China is highlighted in the figure above as well as the one below. China has more than doubled its per capita GDP in the past 5 years, through reducing dependency ratios, as the population has moved to urban areas. Half of China is now urbanized and free from subsistence agriculture, as shown in the figure below. This shift in the location of the Chinese population is the largest migration in history and has been accompanied by improved education and increased openness to trade with the rest of the world. China and India's labour productivity is growing at a rate 500% faster than that of the developed world.

The spur to world economic growth over the past three decades has been economic integration. While between 1980 and 2005 real world GDP increased by 32%, world imports and exports grew 700% and global foreign investment flows increased by 1800%. Logistics chains have become more efficient and have diminished distances, while virtual proximity is almost universal (internet, cell phones and computing power). Global integration has spurred sustained growth and will possibly lead to more cross border alliances and economic unions beyond individual countries, such as the European Union (EU), East African Community (EAC), the Southern African Development Community (SADC), and the Common Market for Eastern and Southern Africa (COMESA).

Between 1981 and 2005, in the developing world the number of people living below US$ 1.25 per day more than halved from 52% to 25% and between 1997 and 2007 the number of Africans living below US$ 1.25 per day fell from 59% to 50%. Global trade grew twice as fast as GDP over the past 3 decades as a result of lower import tariffs and more efficient transport and communication.

*Figure F – 5: Reduction in dependency ratios – Urbanisation*




*Source: World Bank, World Development Indicators, 2013*

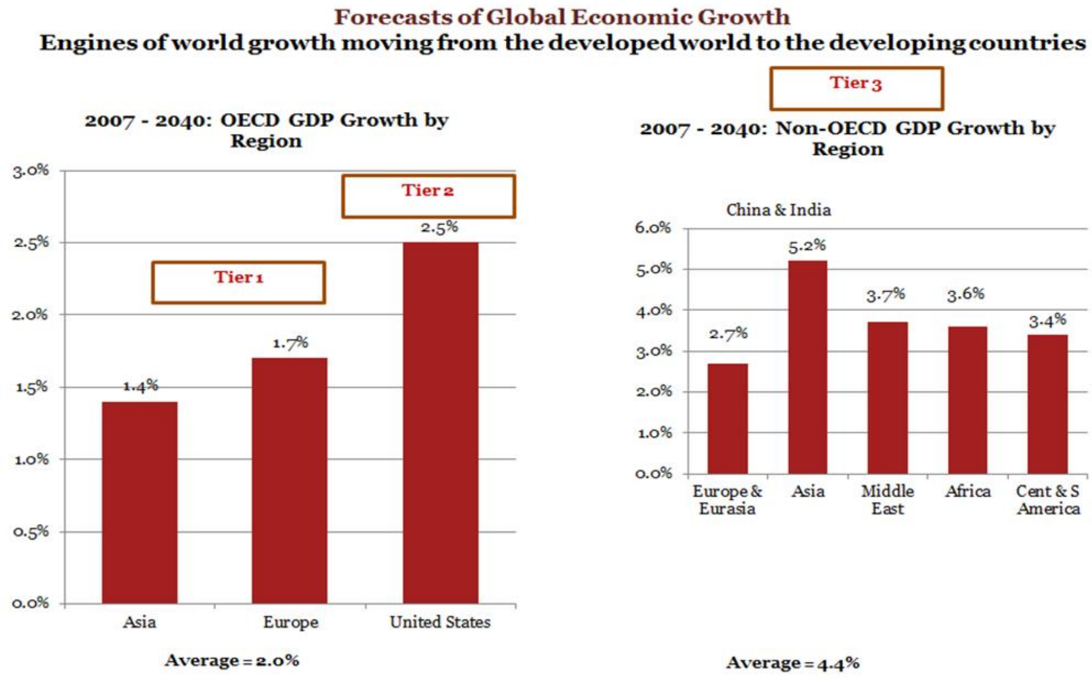
Kenya has increased its percentage of urban population over this period as people have moved to the cities driven by the desire for higher material benefits, as shown in the figure above. World economic growth for the forecast period is expected to move in three tiers or at three speeds.

Tier 1 comprising OECD Europe and Asia (Japan and South Korea) are forecast to be the slowest growing regions, struggling to emerge from the 2008/2009 global credit malaise, which was the deepest recession experienced since the 1930's, as shown in the figure below.

Tier 2 countries of North America, are likely to grow faster than Tier 1 as it benefits from the monetary stimulus of the United States of America and has been less affected than OECD Asia and Europe by the economic meltdown of 2008/2009.

Tier 3 comprising the emerging markets and developing economies are forecast to have the fastest growth.in China and India, in particular recovered quickly post the 2008/2009 recession, and high growth is expected to continue going forward. China introduced a US$ 586b infrastructure package so that its economy and its trading partners weathered the fall in the advanced economies' demand well. India has a large internal market, where 75% of the populations depend on farming for income, so that domestic demand ensures that economic growth is maintained. Africa is experiencing good export growth and domestic demand. However, low savings and investment rates as well as a limited quantity, and quality of infrastructure hamper Africa.

*Figure F – 6: Three tiered (speeds) world economic growth 2007 to 2040*




*Source: EIA International Energy Outlook*

## *Kenya Economic Growth*

Kenya is the biggest economy in East Africa, bordering the Indian Ocean between Somalia and Tanzania. The country comprises 580,367 square km and shares boundaries with Ethiopia, Somalia, South Sudan, Tanzania and Uganda. Principal natural resources include limestone, soda ash, salt, gemstones, fluorspar, zinc, diatomite, gypsum, wildlife, hydropower, and although arable land comprises only 9.48% of the surface area, tea, horticultural products and coffee are key exports.

The economy is relatively underdeveloped, with the Kenya National Bureau of Statistics describing employment in Kenya as categorized into three sectors, namely formal (modern), secondly informal and finally small scale agriculture or subsistence farming and pastoralist activities (Kenya National Bureau of Statistics, 2014:65). However this last sector is excluded from this report. The employment in the first two sectors is given as 12.782 million in 2012, but the World Bank, in its World Development indicators (2014), gives the total labour force of Kenya at 16.697milliion. So that almost 4 million breadwinners do not make enough goods or output to be entered into the Kenya national accounts.

The urban population of Kenya stood at 24.4% of the total population in 2012 (World Bank, 2014) and as indicated above, a key ingredient of material development for a country's inhabitants is to move away from subsistence farming, to increase skill levels and reduce dependency ratios. The incidence of poverty is high. According to the Kenya Population and Housing Census of 2009, 45.2% or almost half of the population was living below the poverty line. The poverty line is determined based on the expenditure needed to purchase a basket of food that meets minimum nutritional requirements in addition to the cost of basic non-food needs (Kenya National Bureau of Statistics 2014:291).

Kenya is a relatively small economy by world standards. It is ranked 84$^{th,}$ at US$ 33.6b, out of the global universe of 214 countries, monitored by the World Bank in their World Development Indicators in 2011, just behind Ghana at US$ 39.2b, but ahead of Ethiopia and Cameroon at US$ 30.2b and US$ 25.2b respectively

(See the table below). These GDP figures were somewhat smaller than other countries in Africa such as to Nigeria, Angola and Algeria with GDP's of US$ 262.6b, US$ 114.2b and US$ 208b respectively. However all three of these countries have the asset of oil to thank largely for their prosperity, something that Kenya may well emulate.

*Table F – 3: Kenya in GDP $US billion world rankings*

| Rank | Country | 2011 |
|---|---|---|
| **80** | Lebanon | 40.1 |
| **81** | Ghana | 39.2 |
| **82** | Macao SAR, China | 36.4 |
| **83** | Yemen, Rep. | 33.8 |
| **84** | **Kenya** | **33.6** |
| **85** | Ethiopia | 30.2 |
| **86** | Jordan | 28.8 |
| **87** | Latvia | 28.3 |
| **88** | Turkmenistan | 28.1 |
| **89** | Panama | 26.8 |
| **90** | Cameroon | 25.2 |

*Source: World Bank*

The structure of the economy currently comprises a relatively large primary sector, at 26.4% of GDP in 2013, made up of the growing of crops, with horticulture as its biggest segment (19.4%). This is important as this is where the key export commodities of tea, coffee and cut flowers, amongst others, originate. Other primary sector components are set to boost the economy in the forecast period, particularly oil and coal. The secondary sector is relatively undeveloped, at 14.7% in 2013. However in the forecast period to 2040 it is unlikely to become a bigger percentage of GDP as the tertiary sector is forecast to grow from its current level of 49.0% in 2013, as services grow and Kenya retains its role as the logistics and financial hub of East Africa. Proposals such as a monetary union in East Africa are a possibility with Kenya playing a leading role. Kenya is set to remain the logistics hub serving Uganda, Rwanda, Burundi, Northern Tanzania, South Sudan, and Ethiopia through Mombasa, and the port of Lamu, where the LAPSSET Corridor looks likely to be developed in the forecast timeframe. This corridor will require enormous investment locally and from abroad and security issues need to be addressed. The construction of a standard gauge railway line from Mombasa to Nairobi and onward to western Kenya has commenced.

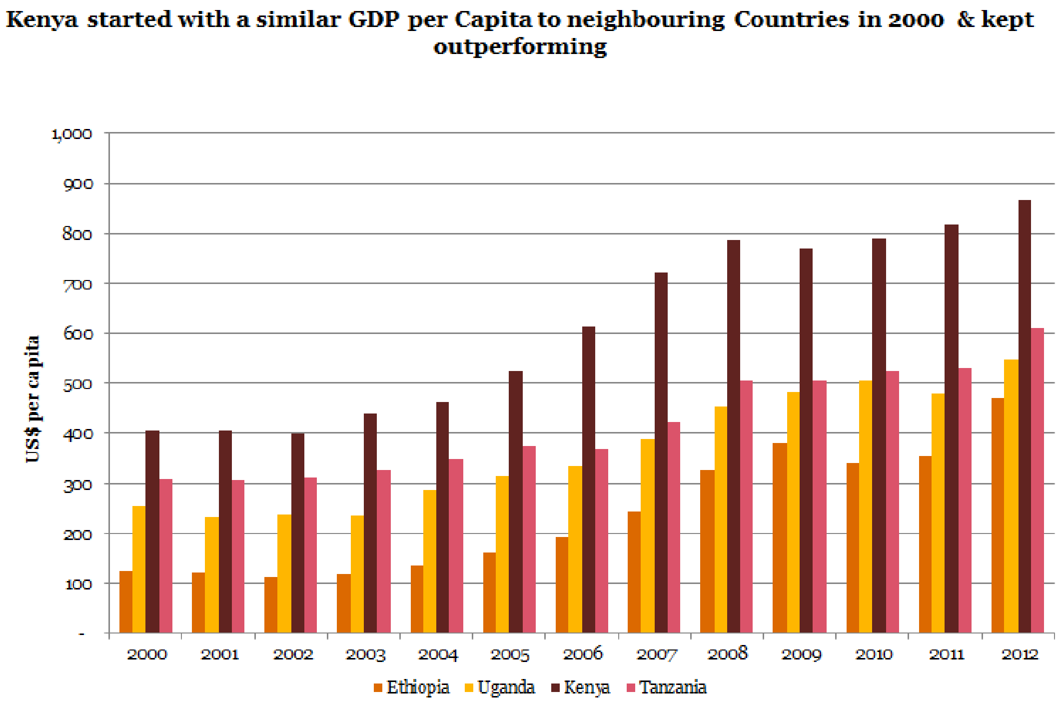
*Table F – 4: Structure of the Kenyan economy*

| GDP BY KIND OF ECONOMIC ACTIVITY (KSh Million) | Current Prices 2013 | % of Total 2013 | Constant 2001 Prices 2009 | Constant 2001 Prices 2013 | AAI 2009-2013 |
|---|---|---|---|---|---|
| Agriculture and Forestry | 961 819 | 25.3% | 299 431 | 346 935 | 3.7% |
| Growing of crops & horticulture | 735 490 | 19.4% | 200 700 | 234 724 | 4.0% |
| Farming of animals | 186 829 | 4.9% | 83 914 | 96 205 | 3.5% |
| Agric & animal husbandry services | 13 895 | 0.4% | 3 659 | 3 717 | 0.4% |
| Forestry and Logging | 25 605 | 0.7% | 11 158 | 12 289 | 2.4% |
| Fishing | 17 227 | 0.5% | 5 564 | 6 422 | 3.7% |
| Mining and quarrying | 22 480 | 0.6% | 6 163 | 8 102 | 7.1% |
| ***PRIMARY SECTOR*** | **1 001 526** | **26.4%** | **311 158** | **361 459** | **3.8%** |
| Manufacturing | 338 378 | 8.9% | 137 060 | 160 247 | 4.0% |
| Food, Beverages and Tobacco | 113 385 | 3.0% | 41 810 | 48 384 | 3.7% |
| All other manufacturing | 224 993 | 5.9% | 95 250 | 111 863 | 4.1% |
| Electricity and water supply | 53 193 | 1.4% | 30 397 | 37 915 | 5.7% |
| Electricity supply | 24 027 | 0.6% | 22 348 | 28 634 | 6.4% |
| Water supply | 29 166 | 0.8% | 8 049 | 9 281 | 3.6% |
| Construction | 166 906 | 4.4% | 49 270 | 59 434 | 4.8% |
| ***SECONDARY SECTOR*** | **558 477** | **14.7%** | **216 727** | **257 596** | **4.4%** |
| Wholesale and retail trade, repairs | 387 752 | 10.2% | 143 460 | 194 738 | 7.9% |
| Hotels and restaurants | 56 520 | 1.5% | 18 993 | 20 366 | 1.8% |
| Transport and Communications | 345 616 | 9.1% | 171 994 | 212 282 | 5.4% |
| Transport and storage | 269 450 | 7.1% | 100 205 | 120 919 | 4.8% |
| Post and telecommunications | 76 167 | 2.0% | 71 789 | 91 363 | 6.2% |
| Financial Intermediation | 183 973 | 4.8% | 55 375 | 74 353 | 7.6% |
| Real estate, renting & business services | 156 161 | 4.1% | 75 675 | 87 208 | 3.6% |
| Dwellings, owner occupied & rented | 71 824 | 1.9% | 38 947 | 45 840 | 4.2% |
| Renting & business services | 84 337 | 2.2% | 36 728 | 41 368 | 3.0% |
| Public administration and defence | 256 025 | 6.7% | 46 031 | 51 935 | 3.1% |
| Education | 253 768 | 6.7% | 82 952 | 100 466 | 4.9% |
| Health and social work | 72 914 | 1.9% | 31 352 | 35 143 | 2.9% |
| Other community, social & personal services | 132 312 | 3.5% | 52 156 | 59 624 | 3.4% |
| Private households with employed persons | 17 082 | 0.4% | 4 342 | 4 699 | 2.0% |
| ***TERTIARY SECTOR*** | **1 862 123** | **49.0%** | **682 330** | **840 814** | **5.4%** |
| Less: FISIM | (36 818) | -1.0% | (11 945) | (13 778) | 3.6% |
| TOTAL GROSS VALUE ADDED | **3 385 308** | **89.1%** | **1 198 270** | **1 446 091** | **4.8%** |
| Taxes less subsidies on Products | 412 680 | 10.9% | 196 117 | 240 058 | 5.2% |
| **TOTAL G.D.P. AT MARKET PRICES** | **3 797 988** | **100.0%** | **1 394 387** | **1 686 149** | **4.9%** |

Source: Kenya National Bureau of Statistics,2014:20,22; AAI = Average Annual Increase

Kenya has made significant discoveries of oil and potentially of natural gas. Tullow and Africa Oil, joint partners in the exploration of the East Africa Rift Basin, have revealed an estimated 300 million barrels of reserves in North West Kenya. This compares favourably to oil producers like Egypt which had 3 900 million barrels of reserves in 2013 and Tunisia which had 400 million barrels of reserves in 2013. These discoveries are potential game changers for the economy of Kenya particularly if the price of crude oil maintains its current level of over US$ 100 a barrel. These discoveries are boosting investment. The Government of Kenya is progressing plans to build a 32 berth port at Lamu, North of Mombasa, with a transport corridor of pipelines, railway, roads and airports to link its new oil fields as well as the East African states of Ethiopia and South Sudan, to the coast, at a cost of around US$ 25b (LAPSSET Project). Kenya is the dominant economy in East Africa and is leading the way in terms of GDP per capita growth, as shown in the figure below.

*Figure F - 7: Relative East African GDP per capita*




*Source: World Bank 2014*

## *Vision 2030 economic pillars-priority sectors*

Six sectors were identified on the basis of their potential to contribute to the 10% GDP growth. These are listed below with comments as to their capability to realise the annual 10% GDP target.

1. **Tourism** – where socio/political unrest and terrorism are inhibitors to growth.

2. **Agriculture** – where there is reliance on too few basic products with volatile prices.

3. **Wholesale and Retail Trade** – potentially a large employer and conduit to other countries inland.

4. **Manufacturing** – Need to develop beyond small-scale consumer goods (such as plastic, furniture, batteries, textiles, clothing, soap, cigarettes, flour), and agricultural products, horticulture, oil refining; aluminium, steel, lead; cement and commercial ship repair.

5. **Information and Communications Technology (ICT) and Business Process Outsourcing (BPO)** – Widen access to Internet and communication.

6. **Financial Services** – Increase availability of credit particularly for small, medium and micro enterprises.

## *Foundation for National transformation*

- Infrastructure – requires significant investment such as LAPSSET corridor project
- Public Sector Reforms – clamping down on corruption and replacing it with good governance
- Education, Science and Technology – expansion of secondary and tertiary facilities

- Health – widening of preventative medicine and access to health care
- Security – ridding the nation of terrorism
- Population, Urbanization and Housing – widening of access to housing
- Environment, water and Sanitation – prevention of pollution and increasing access to clean water

The Vision is being implemented through successive five year, Medium Term Plans (MTP). The first MTP covered the period 2008-2012 and its implementation is on-going.

## *Some notable achievements under the first MTP*

- ✓ Constitution of Kenya,
- ✓ Three undersea Fibre Optic Cables which connect Kenya to the global fibre optic network and link to 5,500 km of terrestrial fibre optic cables covering most parts of the country
- ✓ Increased Government expenditure on development and modernization of infrastructure - roads, energy, airports and ports
- ✓ The Financial Services sector recovered from a low growth of 2.7 % in 2008 to record an average 8 % growth in the past 3 years (2009 and 2011).
- ✓ The transition rate from primary to secondary education increased from 64.1 % in 2008 to 73.3 % in 2011
- ✓ Construction of an additional 124 youth polytechnics and the equipping of 560 youth polytechnics with relevant tools and equipment
- ✓ Student enrolment in both public and private universities increased from 118,000 in 2008 to 198,000 in 2012, an increase of 68% in four years.

## *Scope of The 2nd Medium Term Plans*

- On-going key Vision 2030 Flagship projects
- Priorities arising from the Kenya Constitution, 2010
- Enhancing the development of the country's human resources
- Employment creation especially among the youth
- Increasing the share of exports to GDP especially manufactured exports
- Increasing the share of power generated from green and more cost effective sources
- Increased investment in infrastructure under PPP arrangements
- Taking due cognizance of the recent discovery of oil and other mineral resources in the country and making plans for investment in the requisite infrastructure to facilitate their exploitation.

The Kenya Vision 2030 is the country's long–term development blueprint which aims to create a globally competitive and prosperous country providing a high quality of life for all its citizens. It aspires to transform Kenya from a low income country into a newly industrializing, middle income country by 2030. Vision 2030 is seen to be progressing towards its goals and one of the key ingredients is going to be the lowering of the cost of power and expanding its availability. The aim is to increase the installed power capacity in the country, with an initial plan to build up to 5 538 MW, from the current 1717.8 MW in 2013 within 40 months from September 2013, at a cost of around 10 US cents/KWh, halving the current cost of over 20 US cents/KWh (Second Medium Term Plan 2013 – 2017, 2013:20). Here more geothermal power plants are envisaged as well as the conversion of thermal plants from fuel oil to natural gas. The Export Processing Zones (EPZ) are considered to be important sectors to lead the progress to 10% per annum GDP growth, as they take advantage of their favourable environment such as their tax free status. Key, however, is the extent of Kenya's oil discoveries and how this resource is managed.

The economy is seen to be diversified and not reliant on any particular sector. Agriculture plays a role, tourism plays a role, the financial sector is another large sector and oil, when it comes onstream, should not be allowed to crowd out these other sectors. Dutch disease is being catered for by new legislation comprising regulations, sovereign funds and taxes, (Dutch disease is defined as when an overvalued (strong) exchange rate caused by the high price of a single natural resource, such as a high gold price or high oil price, makes all exports very expensive and uncompetitive on global markets).

Investment as shown in the table below is currently focused on building and structures, with the fastest growing segment being machinery and equipment, as the secondary sector expands.

*Table F – 5: Investment the Kenyan economy*

| **Gross Fixed Capital Formation (KES Million)** | | | | | |
|---|---|---|---|---|---|
| | **Current Prices 2013** | **% of Total 2013** | **Constant 2001 Prices 2009** | **Constant 2001 Prices 2013** | **AAI 2009-2013** |
| **Building & structures** | 340,075 | 46.2% | 131,461 | 155,797 | 4.3% |
| **Transport equipment** | 128,963 | 17.5% | 63,143 | 87,920 | 8.6% |
| **Other machinery & equipment** | 264,474 | 36.0% | 136,956 | 215,445 | 12.0% |
| **Cultivated assets** | 1,759 | 0.2% | 1,169 | 1,192 | 0.5% |
| **Intangible assets** | 82 | 0.0% | 48 | 39 | -5.1% |
| **Total** | **735,352** | **100%** | **332,776** | **460,392** | **8.5%** |

*Source: Kenya National Bureau of Statistics, 2014 - Pages: 31 and 32; AAI = Average Annual Increase*

The table below highlights the point that there is significant pent-up consumer demand in Kenya in that most income is spent on food and beverages and little is spent on more expensive items such as semi-durables like clothing and non-durables such as furniture and motor vehicles.

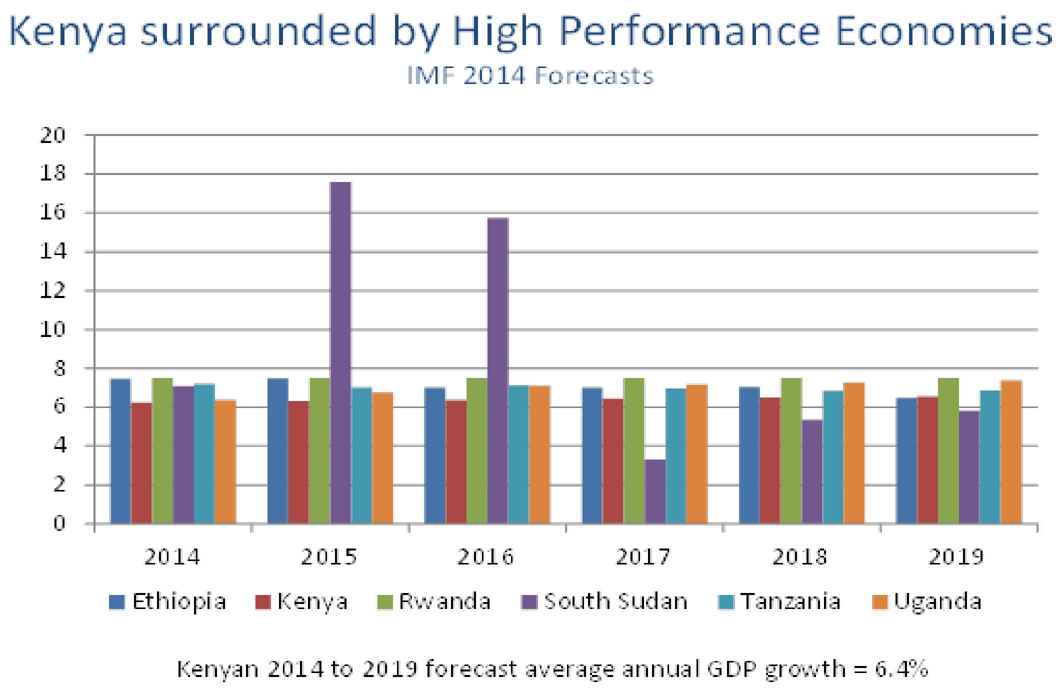
*Table F - 6: Consumption categories in the Kenyan economy*

| **Private Consumption Expenditure (KES Million)** | | |
|---|---|---|
| | **Current Prices 2013** | **% of Total 2013** |
| **Food & beverages** | 1,356,698 | 47.7% |
| **Clothing & footwear** | 71,653 | 2.5% |
| **Housing** | 160,949 | 5.7% |
| **All other goods** | 362,233 | 12.7% |
| **All other services** | 1,036,990 | 36.4% |
| **Direct purchases abroad** | 11,401 | 0.4% |
| **Less: Direct purchases by non-res in Kenya** | (153,596) | -5.4% |
| **Total** | **2,846,328** | **100%** |

*Source: Kenya National Bureau of Statistics, 2014*

Kenya is well positioned to take advantage of the growth of its neighbours as well as the momentum of its own economy. The International Monetary Fund's forecasts for GDP growth for Kenya and its neighbours are highlighted in the figure below are incorporated into the national account projections in Tables F-7 to F-9.

*Figure F – 8: Kenya and its neighbours' GDP growth forecasts*




*Source: IMF 2014 Forecasts*

Tables F-7 to F-9 below outline the three scenarios for the National Accounts of the Kenyan economy for the period 2013 to 2040.

The Base Case (LAPSSET and Moderate Oil) is predicated on:

1) The development of the LAPSSET / North West Corridor,
2) The establishment of recoverable resources of oil of 1 -3 billion barrels and
3) The maintenance of the long term oil price in excess of US$ 100 a barrel in 2014 money.

Government consumption expenditure grows at 6.2% per annum in real terms as the State progresses its socio-economic agenda described above in terms of Vision 2030 and the successive Medium Term Plans.

Exports increase at the fastest rate of all the variables in this scenario.

As the oil fields are exploited the economy develops and moves towards middle income status. Overall GDP growth achieves 6.6% per annum. GDP per capita in US Dollar terms doubles but is not enough to take the nation to middle income status.

*Table F – 7: Base Case - LAPSSET and Moderate recoverable Oil Resources*

| Gross Domestic Product by Type of Expenditure at 2001 Prices KES billions - BASE CASE: LAPSSET & Moderate Oil | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | **2013** | **2015** | **2020** | **2025** | **2030** | **2035** | **2040** | % of Total | AAI 2013-2040 |
| **Final Consumption Expenditure** | 1,590 | 1,770 | 2,350 | 3,219 | 4,394 | 5,997 | 8,186 | 86.50% | 6.30% |
| ***% Change*** | 5.20% | 6.10% | 6.10% | 6.50% | 6.40% | 6.40% | 6.40% | | |
| **Government Consumption Expenditure** | 256 | 287 | 392 | 537 | 719 | 962 | 1,287 | 13.60% | 6.20% |
| ***% Change*** | 9.60% | 6.50% | 6.50% | 6.50% | 6.00% | 6.00% | 6.00% | | |
| **Household Consumption Expenditure** | 1,335 | 1,483 | 1,958 | 2,682 | 3,675 | 5,035 | 6,899 | 72.90% | 6.30% |
| ***% Change*** | 4.50% | 6.00% | 6.00% | 6.50% | 6.50% | 6.50% | 6.50% | | |
| **Gross Capital Formation** | 460 | 557 | 971 | 1,240 | 1,582 | 1,943 | 2,364 | 25.00% | 6.20% |
| ***% Change*** | 2.30% | 10.00% | 7.00% | 5.00% | 5.00% | 4.00% | 4.00% | | |
| **Changes in inventories** | -15.21 | | | | | | | | |
| **Gross Domestic Expenditure** | 2,036 | 2,327 | 3,321 | 4,459 | 5,976 | 7,940 | 10,550 | 111.50% | 6.30% |
| | 4.10% | 7.00% | 6.30% | 6.10% | 6.00% | 5.80% | 5.90% | | |
| **Exports of Goods and Services** | 475 | 564 | 1,012 | 1,630 | 2,181 | 2,919 | 3,906 | 41.30% | 8.10% |
| ***% Change*** | 2.80% | 10.00% | 10.00% | 10.00% | 6.00% | 6.00% | 6.00% | | |
| **Imports of Goods and Services** | 799 | 986 | 1,672 | 2,401 | 3,064 | 3,911 | 4,991 | 52.70% | 7.00% |
| ***% Change*** | 2.80% | 10.10% | 5.00% | 7.50% | 5.00% | 5.00% | 5.00% | | |
| **Total GDP at Constant Prices** | 1,686 | 1,906 | 2,661 | 3,688 | 5,093 | 6,948 | 9,465 | 100.00% | 6.60% |
| ***% Change*** | 4.70% | 6.30% | 8.60% | 6.80% | 6.70% | 6.40% | 6.40% | | |
| **Kenya CPI increase** | **6%** | **5%** | **4%** | **3%** | **3%** | **3%** | **3%** | | **3.4%** |
| **US CPI - Increasing by AEO 2012** | **2.1%** | **2.1%** | **2.0%** | **2.0%** | **2.3%** | **2.3%** | **2.3%** | | **2.2%** |
| **Population millions** | 44 | 47 | 53 | 61 | 70 | 81 | 93 | | 2.80% |
| **GDP per capita US$** | 4,956 | 5,312 | 6,504 | 7,855 | 9,450 | 11,233 | 13,331 | | 3.70% |
| **Oil Price $/barrel Real 2011** | 110 | 109 | 106 | 117 | 130 | 145 | 163 | | 1.50% |
| **Oil Price % change** | -0.60% | -0.60% | -0.60% | 2.10% | 2.10% | 2.20% | 2.30% | | |

Note: AAI% = Average Annual Increase *Source: Kenya National Bureau of Statistics, second Medium Term Plan & G McGregor*

The High Case (LAPSSET and Abundant Oil) is also predicated on:

1) The development of the LAPSSET / North West Corridor,
2) The establishment of over 5 billion barrels of recoverable resources of oil whose production lasts well over the forecast period; and
3) The oil price is retained at a level in excess of US$ 100 a barrel in 2014 money.

The focus for the economy is the growth of exports which initially comprise principally oil, but increasingly manufactured goods as the secondary sector develops. Vision 2030 is realised and the economy develops and moves towards middle income status. Investment as a percentage of GDP is seen to rise to 30% and remain around this level with consumption growing and boosting economic activity. Overall GDP growth achieves 10% per annum. GDP per capita in US Dollar terms increases six fold in US Dollar terms as the nation easily reaches its goal of becoming a middle income country.

*Table F – 8: High case - LAPSSET and abundant proven oil reserves*

| Gross Domestic Product by Type of Expenditure at 2001 Prices KES billions - HIGH CASE: LAPSSET & Abundant Oil | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | **2013** | **2015** | **2020** | **2025** | **2030** | **2035** | **2040** | **% of Total** | **AAI 2013 - 2040** |
| **Final Consumption Expenditure** | 1,590 | 1,770 | 2,383 | 3,448 | 5,184 | 7,795 | 11,722 | 54% | 8% |
| | 5.25% | 6.08% | 7.58% | 8.00% | 8.50% | 8.50% | 8.50% | | |
| **Government Consumption Expenditure** | 256 | 287 | 397 | 584 | 878 | 1,320 | 1,985 | 9% | 8% |
| **% Change from Previous Year** | 9.55% | 6.50% | 8.00% | 8.00% | 8.50% | 8.50% | 8.50% | | |
| **Household Consumption Expenditure** | 1,335 | 1,483 | 1,986 | 2,864 | 4,306 | 6,475 | 9,736 | 45% | 8% |
| **% Change from Previous Year** | 4.46% | 6.00% | 7.50% | 8.00% | 8.50% | 8.50% | 8.50% | | |
| **Gross Capital Formation** | 460 | 557 | 998 | 1,608 | 2,590 | 4,171 | 6,717 | 31% | 10% |
| **% Change from Previous Year** | 2.30% | 10.00% | 10.00% | 10.00% | 10.00% | 10.00% | 10.00% | | |
| **Changes in inventories** | (15) | | | | | | | | |
| **Gross Domestic Expenditure** | 2,036 | 2,327 | 3,381 | 5,056 | 7,774 | 11,966 | 18,438 | 84% | 9% |
| | 4.08% | 6.99% | 8.29% | 8.63% | 9.00% | 9.02% | 9.04% | | |
| **Exports of Goods and Services** | 475 | 564 | 1,035 | 1,865 | 3,361 | 6,057 | 10,914 | 50% | 12% |
| **% Change from Previous Year** | 2.78% | 10.00% | 12.50% | 12.50% | 12.50% | 12.50% | 12.50% | | |
| **Imports of Goods and Services** | 799 | 986 | 1,736 | 2,539 | 3,645 | 5,233 | 7,513 | 34% | 9% |
| **% Change from Previous Year** | 2.78% | 10.10% | 9.00% | 7.50% | 7.50% | 7.50% | 7.50% | | |
| **Total GDP at Constant Prices** | 1,686 | 1,906 | 2,680 | 4,382 | 7,490 | 12,790 | 21,840 | 100% | 10% |
| **% Change from Previous Year** | 4.69% | 6.30% | 9.40% | 10.93% | 11.30% | 11.29% | 11.30% | | |
| **Kenya Inflation** | **6%** | **5%** | **4%** | **3%** | **3%** | **3%** | **3%** | | **3.4%** |
| **US CPI - Increasing by AEO 2012** | **2.1%** | **2.1%** | **2.0%** | **2.0%** | **2.3%** | **2.3%** | **2.3%** | | **2.2%** |
| **Population millions** | 44 | 47 | 53 | 61 | 70 | 81 | 93 | | 3% |
| **GDP per capita US$** | 4,956 | 5,312 | 6,552 | 9,332 | 13,898 | 20,676 | 30,760 | | 7% |
| **Oil Price $/barrel Real 2011** | 110 | 109 | 106 | 117 | 130 | 145 | 163 | | 1% |
| **Oil Price % change** | -0.58% | -0.58% | -0.58% | 2.14% | 2.14% | 2.19% | 2.27% | | |
| | | | | | | | | | |
| | | | | | | | | | |

Note: AAI% = Average Annual Increase

*Source: Kenya National Bureau of Statistics, second Medium Term Plan & G McGregor*

The Low Case (Partial Implementation of LAPSSET within the forecast period and the identification of limited reserves of oil which become depleted during the forecast period) realizes GDP growth of 4.8% per annum from 2013 to 2040. The growth of exports are still the driving force behind economic activity as the oil fields are exploited but not enough capital is available to fully complete the LAPSSET North West logistics corridor. GDP per capita increases by around 70% over the 27 year period and this is not enough to raise the standard of living of Kenyans to middle income status.

*Table F – 9: Low case - partial implementation LAPSSET limited oil reserves*

| | 2013 | 2015 | 2020 | 2025 | 2030 | 2035 | 2040 | % of Total | AAI 2013 - 2040 |
|---|---|---|---|---|---|---|---|---|---|
| **Final Consumption Expenditure** | 1,590 | 1,770 | 2,304 | 2,826 | 3,467 | 4,255 | 5,224 | 88.30 % | 4.50 % |
| | 5.20 % | 6.10% | 4.00 % | 4.20 % | 4.20 % | 4.20 % | 4.20 % | | |
| **Government Consumption Expenditure** | 256 | 287 | 383 | 488 | 623 | 796 | 1,015 | 17.20% | 5.20 % |
| **% Change from Previous Year** | 9.60 % | 6.50% | 4.00 % | 5.00 % | 5.00 % | 5.00 % | 5.00 % | | |
| **Household Consumption Expenditure** | 1,335 | 1,483 | 1,921 | 2,337 | 2,843 | 3,459 | 4,209 | 71.10% | 4.30 % |
| **% Change from Previous Year** | 4.50 % | 6.00% | 4.00 % | 4.00 % | 4.00 % | 4.00 % | 4.00 % | | |
| **Gross Capital Formation** | 460 | 557 | 935 | 1,084 | 1,256 | 1,457 | 1,689 | 28.50 % | 4.90 % |
| **% Change from Previous Year** | 2.30 % | 10.00 % | 3.00 % | 3.00 % | 3.00 % | 3.00 % | 3.00 % | | |
| **Changes in inventories** | (15) | | | | | | | | |
| **Gross Domestic Expenditure** | 2,036 | 2,327 | 3,239 | 3,909 | 4,723 | 5,712 | 6,913 | 116.8% | 4.60 % |
| | 4.10 % | 7. 0% | 3.7% | 3.8% | 3.9% | 3.9% | 3.9% | | |
| **Exports of Goods and Services** | 475 | 564 | 952 | 1,158 | 1,409 | 1,715 | 2,086 | 35.2% | 5.60 % |
| **% Change from Previous Year** | 2.80 % | 10.00 % | 3.50 % | 4.00 % | 4.00 % | 4.00 % | 4.00 % | | |
| **Imports of Goods and Services** | 799 | 986 | 1,625 | 1,883 | 2,183 | 2,593 | 3,08 | 52.0 | 5.10 % |
| **% Change from Previous Year** | 2.8% | 10.1% | 2.0% | 3.0% | 3.0% | 3.50 % | 3.5% | | |
| **Total GDP at Constant Prices** | 1,686 | 1,906 | 2,566 | 3,185 | 3,949 | 4,833 | 5,920 | 100% | 4.8% |
| **% Change from Previous Year** | 4.7% | 6.3% | 4.7% | 4.4% | 4.4% | 4.1% | 4.1% | | |
| **Kenya Inflation** | 6% | 5% | 4% | 3% | 3% | 3% | 3% | | 3.4% |
| **US CPI - Increasing by AEO 2012** | 2.1% | 2.1% | 2.0% | 2.0% | 2.3% | 2.3% | 2.3% | | 2.2% |
| **Population millions** | 44 | 47 | 53 | 61 | 70 | 81 | 93 | | 2.8% |
| **GDP per capita US$** | 4,956 | 5,312 | 6,273 | 6,782 | 7,328 | 7,814 | 8,338 | | 1.9% |
| **Oil Price $/barrel Real 2011** | 110 | 109 | 106 | 117 | 130 | 145 | 163 | | 1.5% |
| **Oil Price % change** | -0.6% | -0.6% | -0.6% | 2.1% | 2.1% | 2.2% | 2.3% | | |

Note: AAI% = Average Annual Increase

*Sources: Kenya National Bureau of Statistics, second Medium Term Plan, US Energy Information Administration's Annual Energy Outlook 2012 & G McGregor*

# Kenya Petroleum Product Forecasts

## Introduction

The key objective is to forecast the domestic demand for liquid fuels for Kenya for the period 2013 to 2040. Demand is a function of several components, but chiefly of real price, real income and other factors such as urbanisation, substitute products and complementary products, where applicable. Liquid fuels demand is driven in the broader sense by the following variables:

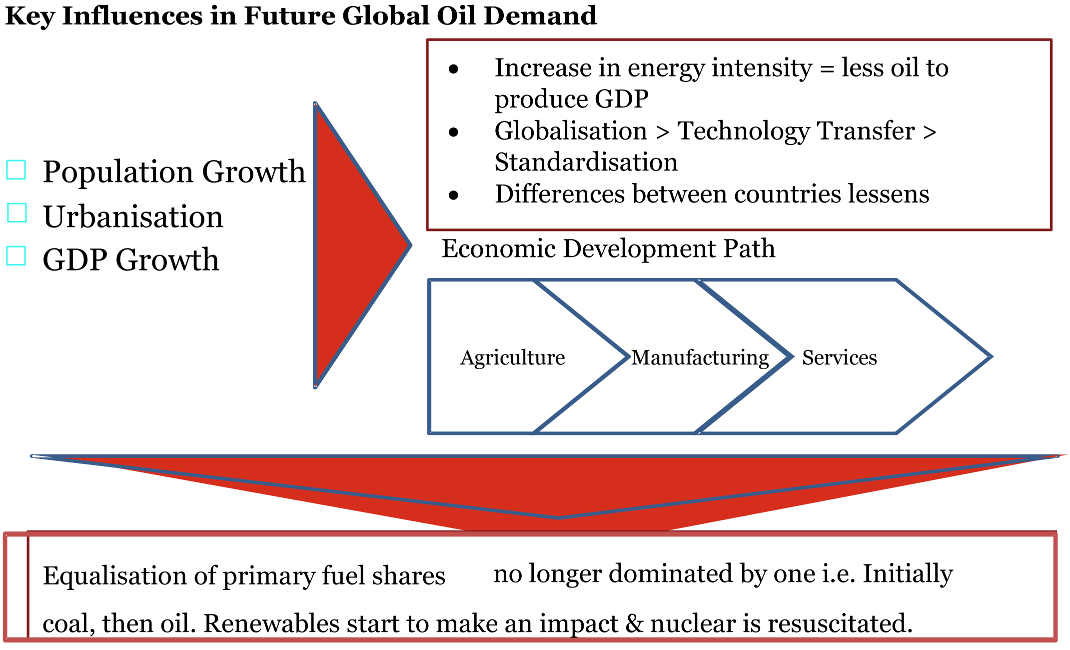
The International economy and the effects this has on the growth of the economy in question. The world oil markets and consequently the price of crude oil and the prices of refined petroleum products.

Domestic factors that influence economic activity of the local economy.

As discussed in sections above, the principal factors that drive petroleum product consumption are economic growth and world oil demand. These two drivers were discussed above and are shown in the figure below. The objective of this section is to derive the individual forecasts for the main fuels for the Kenya economy. Figure F-9 shows how the topics discussed in the initial Chapters link together to arrive at this point.

Table F-4 showed how the different sectors of the Kenya economy performed between 2009 and 2013. The envisaged growth of the tertiary sector building on the robust base of the primary sector is evidence of the developing maturity of the economy. This is highlighted in the figure below and was discussed in earlier.

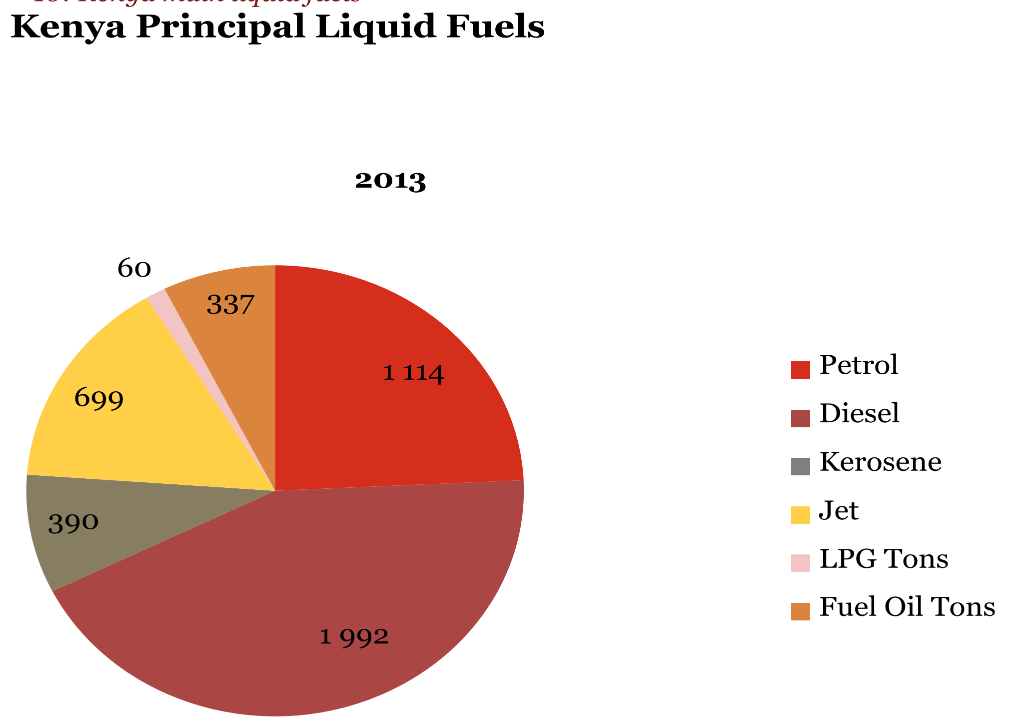
*Figure F – 9: Factors that influence petroleum product forecasts*




*Source: PwC Consortium*

The predominant fuels in the Kenya economy are petrol and diesel as shown in the figure below:

*Figure F – 10: Kenya main liquid fuels*




*Source: PwC Consortium*

## *Petrol econometric model*

Economic modeling and the use of econometrics are processes whereby unknown variables in the future are narrowed down to focus planning and budgeting to the benefit of the organisation. Economic modeling provides greater clarity and enhances the ability to optimise opportunities on the way forward for an organisation. The model below uses real Household Consumption Expenditure (PCE) as the demand enabling (income) element, the real price of petrol as the constraint and the lagged dependent variable as the variable that captures the elements that change future consumption of the dependent variable due to items that change consumption in the dependent variable as time elapses. Regression 1.0 outlines the key relationships in the model built to forecast petrol consumption and the resultant equation was as follows:

*Equation F – 1: Regression 1.0*

$$PETLOG_t = \beta PETPRILOG_t + \mu PCELOG_t + \gamma PLAGLOG_{t-1} + \varepsilon_t$$

Where:

$PETLOG_t$ = volume of petrol in year t

$PETPRILOG_t$ = real price of petrol in year t

$PCELOG_t$ = real Final Household Consumption Expenditure in year t

$PLAGLOG_{t-1}$ = the volume of petrol lagged one year

$\varepsilon_t$ = assumed random error term

C, $\beta$, $\mu$ and $\gamma$ are coefficients to be estimated

Dependent Variable: PETLOG
Method: Least Squares
Date: 07/02/14 Time: 20:47
Sample: 2001 2013
Included observations: 13

| Variable | Coefficient | Std. Error | t-Statistic | Prob. |
|---|---|---|---|---|
| PCELOG | 0.012859 | 0.118368 | 0.108634 | 0.9156 |
| PETPRILOG | -0.178181 | 0.133403 | -1.335661 | 0.2113 |
| PLAGLOG | 1.112649 | 0.201856 | 5.512101 | 0.0003 |

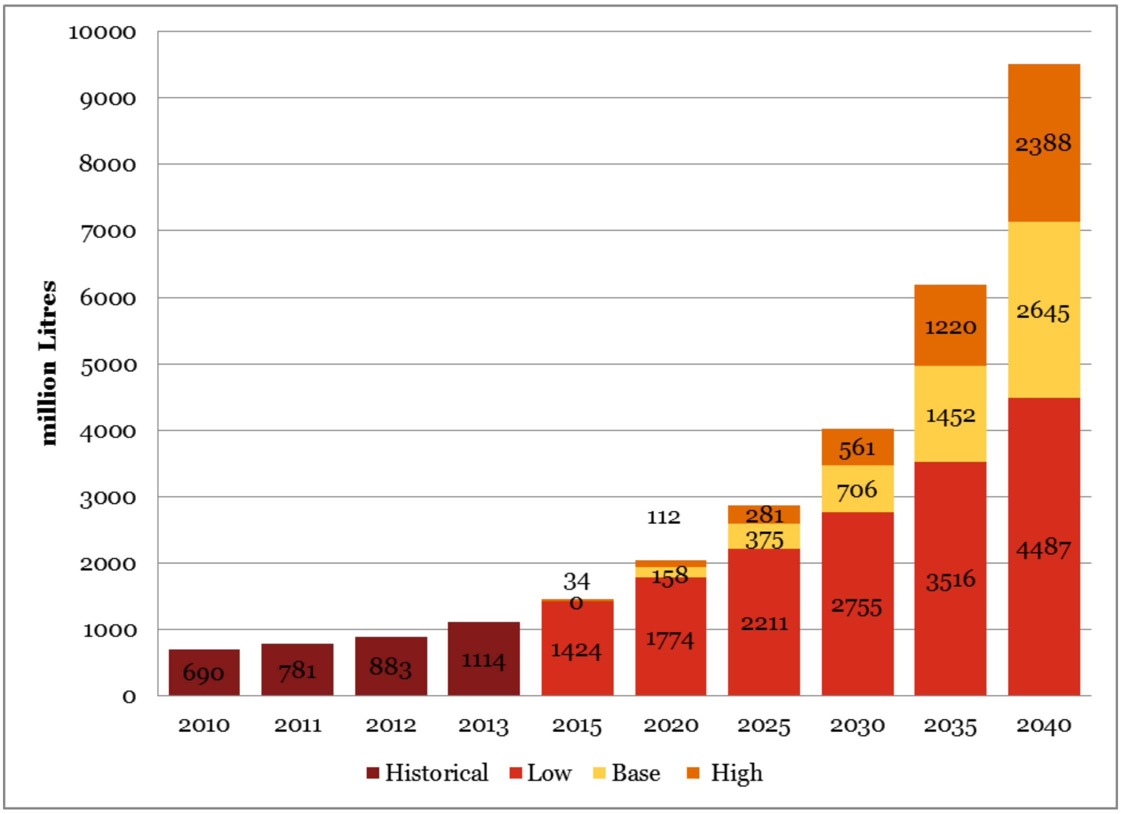
| | | | |
|---|---|---|---|
| R-squared | 0.903344 | Mean dependent var | 6.371504 |
| Adjusted R-squared | 0.884012 | S.D. dependent var | 0.290106 |
| S.E. of regression | 0.098801 | Akaike info criterion | -1.592240 |
| Sum squared resid | 0.097617 | Schwarz criterion | -1.461867 |
| Log likelihood | 13.34956 | Durbin-Watson stat | 2.012402 |

Despite having the correct signs as per economic theory, whereby price as the constraint has a negative coefficient and income (PCE) has a positive (enabling) coefficient and the model having a relatively good fit, as evidenced by the high adjusted R-squared, this regression did not have good predictive capabilities. The relative weight of the lagged variable distorted the forecasts at the expense of income, as shown by the high t statistic for the lagged variable and low statistics for the other two variables.

Petrol volumes are relatively sensitive to price compared to diesel but as the real petrol price is expected to be flat in the forecast period as opposed to the decline in the prior period, petrol volumes will grow in line with buoyant economic growth between 2014 to 2040 in the Base Case. Petrol volumes are projected to increase just over 5 fold in the 26 year forecast period compared to the around 2.5 times experienced in the 13 year period from 2000 to 2013. However as can be seen the time-span is half as long and economic growth is projected to be higher in the forecast period.

The petrol forecasts for the three scenarios are shown below. The base case of LAPSSET and Moderate Proven Oil Reserves sees petrol growth at 6.6% per annum slightly higher than PCE growth of 6.3% over the forecast period. Petrol will become more of a factor towards the end of the forecast period and in the high growth case with abundant oil reserves and, as more motor vehicles are purchased.

*Figure F – 11: Petrol demand forecasts 2014 to 2040*




*Source: PwC Consortium*

*Table F - 10: Compound annual growth (CAGR)*

| CAGR | Historical | Low | Base | High |
|---|---|---|---|---|
| **2010-11** | 13.1% | 13.1% | 13.1% | 13.1% |
| **2011-12** | 13.1% | 13.1% | 13.1% | 13.1% |
| **2012-13** | 26.1% | 26.1% | 26.1% | 26.1% |
| **2013-14** | | 13.1% | 13.1% | 14.4% |
| **2015-20** | | 4.5% | 6.3% | 7.0% |
| **2020-25** | | 4.5% | 6.0% | 7.0% |
| **2025-30** | | 4.5% | 6.0% | 7.0% |
| **2030-35** | | 5.0% | 7.5% | 9.0% |
| **2035-40** | | 5.0% | 7.5% | 9.0% |
| **AAI 00 - 13** | | | 6.0% | |
| **AAI 14 - 40** | | 4.7% | 6.6% | 7.8.0% |
| **Note: AAI = Average annual increase** | | | | |

*Source: PwC Consortium*

**Diesel econometric model**

A diesel econometric model is outlined in the table below which comprises Kenya GDP in real terms, Kenya diesel volumes consumed in the country and real Kenya diesel price over the period 2000 to 2013. It is an ordinary least squares regression model.

The equation takes the following form:

$DIESEL_t = + \mu GDP_t - \beta DIESPRIRE_t + \gamma DIESLAG_{t-1} + \varepsilon_t$

Where:

$DIESEL_t$ = volume of gasoil in year t

$GDP_t$ = real Gross Domestic Product in year t

$DIESPRIRE_t$ = real price of gasoil in year t

$DIESLAG_{t-1}$ = the volume of petrol lagged one year

$\varepsilon_t$ = assumed random error term

$\mu$, $\beta$ and $\gamma$ are coefficients to be estimated

*Table F – 11: Regression 2.0*

Dependent Variable: DIESEL
Method: Least Squares
Date: 07/02/14 Time: 20:41
Sample: 2001 2013
Included observations: 13

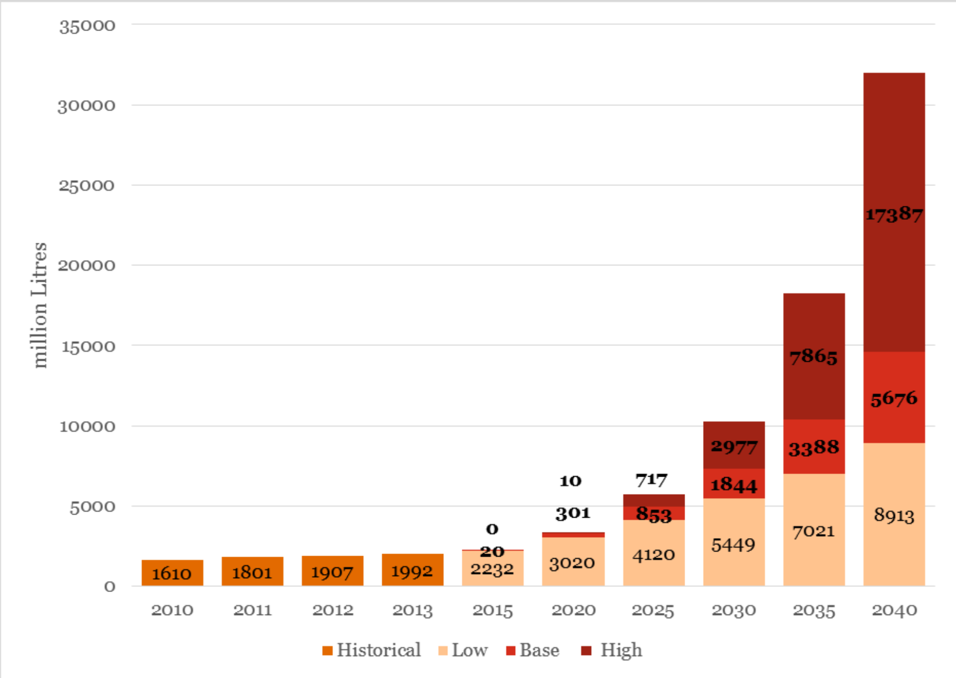
| Variable | Coefficient | Std. Error | t-Statistic | Prob. |
|---|---|---|---|---|
| GDP | 0.000527 | 0.000249 | 2.113340 | 0.0607 |
| DIESPRIRE | -3.119712 | 1.720298 | -1.813472 | 0.0998 |
| DIESLAG | 0.725699 | 0.175321 | 4.139264 | 0.0020 |

| | | | |
|---|---|---|---|
| R-squared | 0.959122 | Mean dependent var. | 1354.902 |
| Adjusted R-squared | 0.950947 | S.D. dependent var. | 433.8804 |
| S.E. of regression | 96.09577 | Akaike info criterion | 12.16774 |
| Sum squared resid. | 92343.97 | Schwarz criterion | 12.29811 |
| Log likelihood | -76.09032 | Durbin-Watson stat | 2.624496 |

Regression 2.0 above proved to have good predictive capability as the signs and coefficients match what would be expected from economic theory i.e. the quantity demanded falls as the price rises (negative coefficient) and the quantity demanded rises as GDP income rises (positive coefficient). The model has a relatively large sample of 13 annual observations and the t statistics are significant indicating that each variable is meaningful. The adjusted R squared is close to one showing that the overall fit of the model to the data is good. The Durbin-Watson statistic is near 2 indicating that serial correlation is absent and as can be expected from the high R

squared, the standard errors are low. This model was used for predicting diesel volumes as outlined in the figure below. Diesel volumes will feed off expected higher GDP growth in the forecast period and grow faster during 2014 to 2040 than 2000 to 2013 in the Base Case. Diesel volumes are forecast to increase just under 7 times in the 26 year period 2014 2040 compared to the around 2.5 times experienced in the 13 year period from 2000 to 2013. However the time-span is half as long in the latter period and economic growth is projected to be higher in the forecast period.

*Figure F – 12: Diesel forecasts 2014 to 2040*




*Source: PwC Consortium*

*Table F – 12: Gasoil – compound annual growth (CAGR)*

| CAGR | Historical | Low | Base | High |
|---|---|---|---|---|
| **2010-11** | 11.9% | 11.9% | 11.9% | 11.9% |
| **2011-12** | 5.9% | 5.9% | 5.9% | 5.9% |
| **2012-13** | 4.5% | 4.5% | 4.5% | 4.5% |
| **2013-14** | | 5.9% | 6.3% | 6.3% |
| **2015-20** | | 6.2% | 8.1% | 8.1% |
| **2020-25** | | 6.4% | 8.4% | 11.3% |
| **2025-30** | | 5.8% | 8.0% | 12.5% |
| **2030-35** | | 5.2% | 7.4% | 12.2% |
| **2035-40** | | 4.9% | 7.0% | 11.8% |
| **AAI 00 – 13** | | | 6.5% | |
| **AAI 14 – 40** | | 5.7% | 7.7% | 11.0% |
| **Note: AAI = Average annual increase** | | | | |

*Source: PwC Consortium*

Diesel is the liquid fuel that serves as the backbone of an economy. It is widely used in most sectors and is the primary refined petroleum product in Kenya. In an economy in its early stage of development i.e. before the widespread use of cars by the bulk of the population, diesel is typically the dominant liquid fuel consumed. In the forecast to 2040 diesel consumption is seen to grow at a faster pace than GDP in both the base case and the high case. However in the low case it is forecast to lag the period 2000 to 2013 as the economy does not reach its full potential.

## *Kerosene Forecasts*

No workable econometric model for kerosene could be built with the available data.

Kerosene is a not a fuel of choice and as such has shown erratic growth over the period from 2000 to 2013. The average annual growth over the period has been around zero. This product is shown to only grow at any significant rate in the low case. It is therefore not expected to grow significantly and the forecast for all the cases are illustrated below.

*Table F – 13: Kerosene forecasts 2014 to 2040*

| Base Case | PCE | Kerosene | % Change | High Case | PCE | Kerosene | % Change | Low Case | PCE | Kerosene | % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Moderate Oil** | Shillings million | Litres million | | Abundant Oil | Shillings million | Litres million | | Limited Oil | Shillings million | Litres million | |
| **2010** | 1,173,376 | 323 | -13.7% | 2010 | 1,173,376 | 323 | -13.7% | 2010 | 1,173,376 | 323 | -13.7% |
| **2011** | 1,207,292 | 341 | 5.3% | 2011 | 1,207,292 | 341 | 5.3% | 2011 | 1,207,292 | 341 | 5.3% |
| **2012** | 1,277,591 | 401 | 17.7% | 2012 | 1,277,591 | 401 | 17.7% | 2012 | 1,277,591 | 401 | 17.7% |
| **2013** | 1,334,547 | 390 | -2.8% | 2013 | 1,334,547 | 390 | -2.8% | 2013 | 1,334,547 | 390 | -2.8% |
| **2015** | 1,482,522 | 397 | 1.0% | 2015 | 1,482,522 | 401 | 2.0% | 2015 | 1,482,522 | 405 | 3.0% |
| **2020** | 1,957,860 | 418 | 1.0% | 2020 | 1,985,565 | 443 | 2.0% | 2020 | 1,920,919 | 470 | 3.0% |
| **2025** | 2,682,438 | 439 | 1.0% | 2025 | 2,863,794 | 489 | 2.0% | 2025 | 2,337,092 | 545 | 3.0% |
| **2030** | 3,675,172 | 461 | 1.0% | 2030 | 4,306,163 | 540 | 2.0% | 2030 | 2,843,429 | 631 | 3.0% |
| **2035** | 5,035,304 | 473 | 0.5% | 2035 | 6,474,991 | 540 | 0.0% | 2035 | 3,459,467 | 732 | 3.0% |
| **2040** | 6,898,803 | 485 | 0.5% | 2040 | 9,736,164 | 540 | 0.0% | 2040 | 4,208,970 | 849 | 3.0% |
| **AAI 00 - 13** | 4.8% | 0.1% | 1.0% | AAI 00 - 13 | 4.8% | 0.1% | 2.0% | AAI 00 - 13 | 4.8% | 0.1% | 3.0% |
| **AAI 14 - 40** | 6.3% | 0.8% | 0.5% | AAI 14 - 40 | 7.7% | 1.2% | 0.0% | AAI 14 - 40 | 4.3% | 3.0% | 3.0% |
| **Note: AAI = Average annual increase** | | | | | | | | | | | |

*Source: PwC Consortium*

## Jet Forecasts

There are no published prices for Jet and hence it was not possible to attempt to build an econometric model for this product with the data available.

Jet volume growth is seen to move in line with the economic growth. As economic activity expands and Kenya develops its position as the financial and logistics hub in East Africa, the use of this liquid fuel will increase. This is shown in the strong correlation of jet average annual growth over the forecast period compared to PCE growth.

*Table F - 14: Jet forecasts 2014 to 2040*

| Base Case | PCE | Jet | % Change | High Case | PCE | Jet | % Change | Low Case | PCE | Jet | % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Moderate Oil** | Shillings million | Litres million | | Abundant Oil | Shillings million | Litres million | | Limited Oil | Shillings million | Litres million | |
| **2010** | 1,173,376 | 748 | 1.0% | 2010 | 1,173,376 | 748 | 1.0% | 2010 | 1,173,376 | 748 | 1.0% |
| **2011** | 1,207,292 | 889 | 18.9% | 2011 | 1,207,292 | 889 | 18.9% | 2011 | 1,207,292 | 889 | 18.9% |
| **2012** | 1,277,591 | 851 | -4.3% | 2012 | 1,277,591 | 851 | -4.3% | 2012 | 1,277,591 | 851 | -4.3% |
| **2013** | 1,334,547 | 699 | -17.9% | 2013 | 1,334,547 | 699 | -17.9% | 2013 | 1,334,547 | 699 | -17.9% |
| **2015** | 1,482,522 | 763 | 4.5% | 2015 | 1,482,522 | 767 | 5.0% | 2015 | 1,482,522 | 752 | 3.0% |
| **2020** | 1,957,860 | 951 | 4.5% | 2020 | 1,985,565 | 979 | 5.0% | 2020 | 1,920,919 | 872 | 3.0% |
| **2025** | 2,682,438 | 1,185 | 4.5% | 2025 | 2,863,794 | 1,249 | 5.0% | 2025 | 2,337,092 | 1,011 | 3.0% |
| **2030** | 3,675,172 | 1,477 | 4.5% | 2030 | 4,306,163 | 1,595 | 5.0% | 2030 | 2,843,429 | 1,172 | 3.0% |
| **2035** | 5,035,304 | 1,931 | 5.5% | 2035 | 6,474,991 | 2,185 | 6.5% | 2035 | 3,459,467 | 1,392 | 3.5% |
| **2040** | 6,898,803 | 2,523 | 5.5% | 2040 | 9,736,164 | 2,993 | 6.5% | 2040 | 4,208,970 | 1,654 | 3.5% |
| **AAI 00 – 13** | 4.8% | 3.8% | 4.5% | AAI 00 - 13 | 4.8% | 3.8% | 5.0% | AAI 00 - 13 | 4.8% | 3.8% | 3.0% |
| **AAI 14 – 40** | 6.3% | 4.9% | 5.5% | AAI 14 - 40 | 7.7% | 5.6% | 6.5% | AAI 14 - 40 | 4.3% | 3.2% | 3.5% |
| **Note: AAI = Average annual increase** | | | | | | | | | | | |

*Source: PwC Consortium*

## Liquid Petroleum Gas (LPG) Forecasts

LPG is a fuel of choice and consumption will increase as economic activity increases. Hence LPG growth in all cases is shown to increase at levels around PCE growth in the forecast period.

*Table F - 15: LPG forecasts 2014 to 2040*

| Base Case | PCE | LPG | % Change | High Case | PCE | LPG | % Change | Low Case | PCE | LPG | % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Moderate Oil** | Shillings million | 000 ' Tons | | Abundant Oil | Shillings million | 000 ' Tons | | Limited Oil | Shillings million | 000 ' Tons | |
| **2010** | 1,173,376 | 64 | 6.7% | 2010 | 1,173,376 | 64 | 6.7% | 2010 | 1,173,376 | 64 | 6.7% |
| **2011** | 1,207,292 | 63 | -2.0% | 2011 | 1,207,292 | 63 | -2.0% | 2011 | 1,207,292 | 63 | -2.0% |
| **2012** | 1,277,591 | 64 | 2.1% | 2012 | 1,277,591 | 64 | 2.1% | 2012 | 1,277,591 | 64 | 2.1% |

| Base Case | PCE | LPG | % Change | High Case | PCE | LPG | % Change | Low Case | PCE | LPG | % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2013** | 1,334,547 | 60 | -6.6% | 2013 | 1,334,547 | 60 | -6.6% | 2013 | 1,334,547 | 60 | -6.6% |
| **2015** | 1,482,522 | 66 | 5.0% | 2015 | 1,482,522 | 67 | 6.5% | 2015 | 1,482,522 | 64 | 3.0% |
| **2020** | 1,957,860 | 84 | 5.0% | 2020 | 1,985,565 | 91 | 6.5% | 2020 | 1,920,919 | 75 | 3.0% |
| **2025** | 2,682,438 | 107 | 5.0% | 2025 | 2,863,794 | 125 | 6.5% | 2025 | 2,337,092 | 87 | 3.0% |
| **2030** | 3,675,172 | 137 | 5.0% | 2030 | 4,306,163 | 171 | 6.5% | 2030 | 2,843,429 | 100 | 3.0% |
| **2035** | 5,035,304 | 183 | 6.0% | 2035 | 6,474,991 | 246 | 7.5% | 2035 | 3,459,467 | 122 | 4.0% |
| **2040** | 6,898,803 | 245 | 6.0% | 2040 | 9,736,164 | 353 | 7.5% | 2040 | 4,208,970 | 149 | 4.0% |
| **AAI 00 - 13** | 4.8% | 4.6 % | 5.0% | AAI 00 - 13 | 4.8% | 4.6 % | 6.5% | AAI 00 - 13 | 4.8% | 4.6 % | 3.0% |
| **AAI 14 - 40** | 6.3% | 5.4 % | 6.0% | AAI 14 - 40 | 7.7% | 6.9 % | 7.5% | AAI 14 - 40 | 4.3% | 3.4 % | 4.0% |
| **Note: AAI = Average annual increase** | | | | | | | | | | | |

*Source: PwC Consortium*

## *Heavy Fuel Oil Forecasts*

Although the econometric model built below conformed to economic theory in that the income variable increased volumes and the price variable decreased volumes, the fit was very poor and hence the predictive ability of the model was jeopardized.

Heavy Fuel Oil is consumed principally in power generation and cement manufacture. If natural gas is found in Kenyan waters or LNG is imported, Fuel Oil is likely to be replaced as the fuel used in power generation. While the refinery was operational a ready supply of Fuel Oil was available. With the refinery now closed fuel oil needs to be imported and its substitution with other more optimum fuels becomes an option.

*Table F – 16: Heavy fuel oil forecasts 2014 to 2040*

| Base Case | GDP | HFO | % Change | High Case | GDP | HFO | % Change | Low Case | GDP | HFO | % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Moderate Oil** | Shillings million | 000' Tons | | Abundant Oil | Shillings million | 000' Tons | | Limited Oil | Shillings million | 000' Tons | |
| **2010** | 1,475,302 | 570 | -3.5% | 2010 | 1,475,302 | 570 | -3.5% | 2010 | 1,475,302 | 570 | -3.5% |
| **2011** | 1,540,520 | 637 | 11.8% | 2011 | 1,540,520 | 637 | 11.8% | 2011 | 1,540,520 | 637 | 11.8% |
| **2012** | 1,610,653 | 423 | -33.7% | 2012 | 1,610,653 | 423 | -33.7% | 2012 | 1,610,653 | 423 | -33.7% |
| **2013** | 1,686,149 | 337 | -20.4% | 2013 | 1,686,149 | 337 | -20.4% | 2013 | 1,686,149 | 337 | -20.4% |
| **2015** | 1,905,634 | 317 | -3.0% | 2015 | 1,905,634 | 310 | -5.0% | 2015 | 1,905,634 | 326 | 0.0% |
| **2020** | 2,660,645 | 272 | -3.0% | 2020 | 2,680,393 | 240 | -5.0% | 2020 | 2,566,179 | 326 | 0.0% |
| **2025** | 3,687,911 | 234 | -3.0% | 2025 | 4,381,838 | 186 | -5.0% | 2025 | 3,184,543 | 326 | 0.0% |
| **2030** | 5,092,659 | 201 | -3.0% | 2030 | 7,489,816 | 144 | -5.0% | 2030 | 3,949,486 | 326 | 0.0% |
| **2035** | 6,948,211 | 155 | -5.0% | 2035 | 12,789,614 | 85 | -10.0% | 2035 | 4,833,478 | 326 | 0.0% |

| Base Case | GDP | HFO | % Change | High Case | GDP | HFO | % Change | Low Case | GDP | HFO | % Change |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2040** | 9,464,708 | 120 | -5.0% | 2040 | 21,839,948 | 50 | -10.0% | 2040 | 5,919,647 | 326 | 0.0% |
| **Price Elasticity = 0.27** | | Income Elasticity = 0.05 | | | | | | | | | |
| **AAI 00 - 13** | 4.2% | -2.8% | -3.0% | AAI 00 - 13 | 4.2% | -2.8% | -5.0% | AAI 00 - 13 | 4.2% | -2.8% | 0.0% |
| **AAI 14 - 40** | 6.6% | -3.8% | -5.0% | AAI 14 - 40 | 10.1% | -7.0% | -10.0% | AAI 14 - 40 | 4.7% | 0.0% | 0.0% |
| **Note: AAI = Average annual increase** | | | | | | | | | | | |

*Source: PwC Consortium*

## *Conclusion*

World economic growth momentum is shifting to the emerging and developing countries and for the first time in 2013 this group of countries consumed more of the world's oil than the developed or advanced economies. The gap in global economic growth rates is expected to continue, driven by population growth, urbanization, the movement away from subsistence agriculture and the harnessing of skills and technology. Oil is forecast to remain a dominant energy carrier particularly in the important logistics sector, as world trade continues to expand.

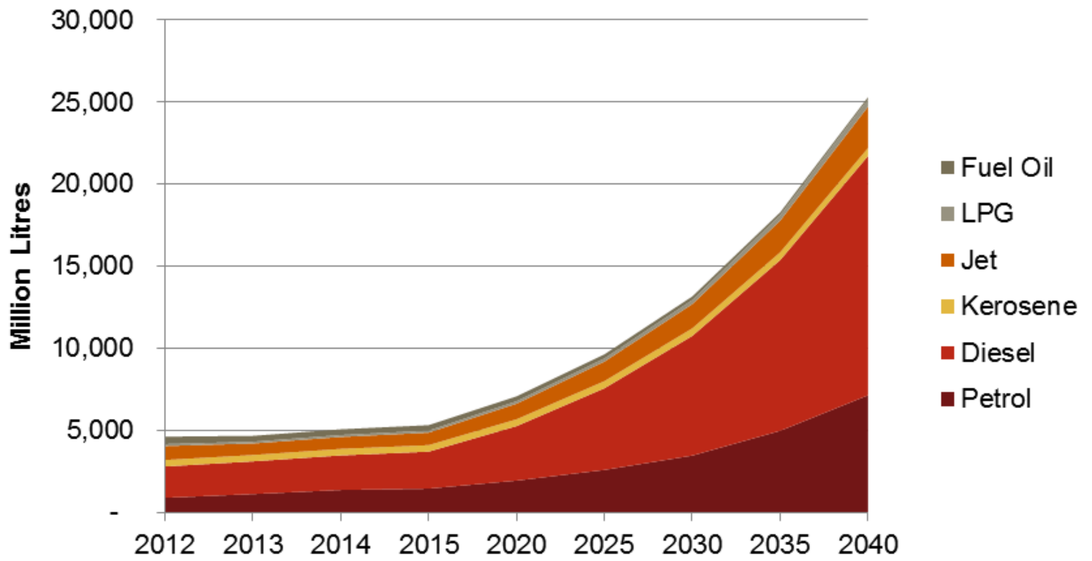
Africa is seen as the new frontier in energy demand. In spite of problems with low rates of savings and investment, as well as a limited quantity and quality of infrastructure and skilled human capital, a large number of countries on the continent are growing strongly and opportunities exist.

The tables above outline Kenya's petroleum product forecasts by product. All products are expected to grow faster in the Base Case in the forecast period than the years between 2000 and 2013 with the exception of fuel oil. This is in recognition that these forecasts take cognisance of the discovery of oil and the fuller implementation of Vision 2030. Renewables will also make an impact in the forecast period however this is more likely in the power sector initially.

Petroleum product volume growth rates are higher than that achieved over the past decade. One of the primary reasons for this higher growth is the essence of this Study, namely the discovery and exploitation of oil and natural gas.

Petrol volumes are relatively sensitive to price and as the real petrol price is expected to be flat in the forecast period as opposed to the decline in the prior period, petrol volumes will grow in line with buoyant economic growth between 2014 to 2040 in the Base Case. Similarly diesel volumes will feed off expected higher GDP growth in the forecast period and grow faster during 2014 to 2040 than 2000 to 2013 in the Base Case.

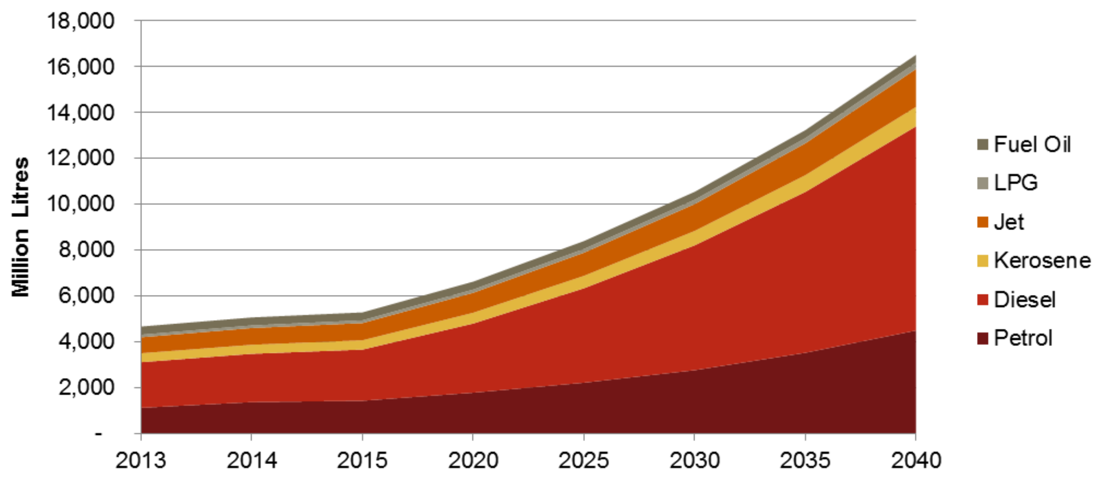
*Figure F -13: Base-case projections*




*Source: PwC Consortium*

The High Case shows Kenya achieving Vision 2030 and needing the liquid fuels growth of 8% per annum to meet this economic growth.

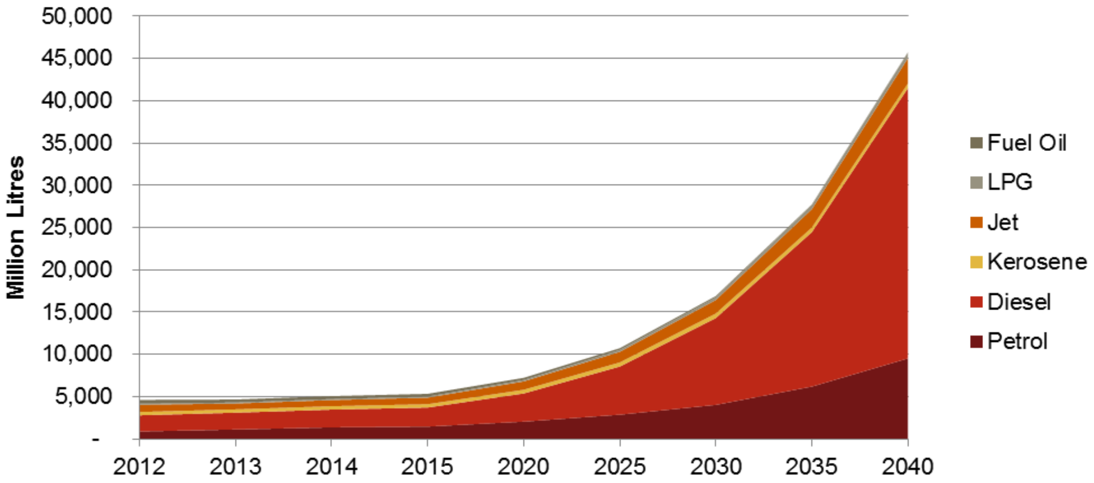
*Figure F – 14: High-case projections*




*Source: PwC Consortium*

The Low Case shows the economy continuing as is with no real impetus from limited new oil discoveries and limited investment and petroleum product growth is lower in the forecast period than during 2000 to 2013 at 4.7%.

*Figure F- 15: Low-case projections*




*Source: PwC Consortium*

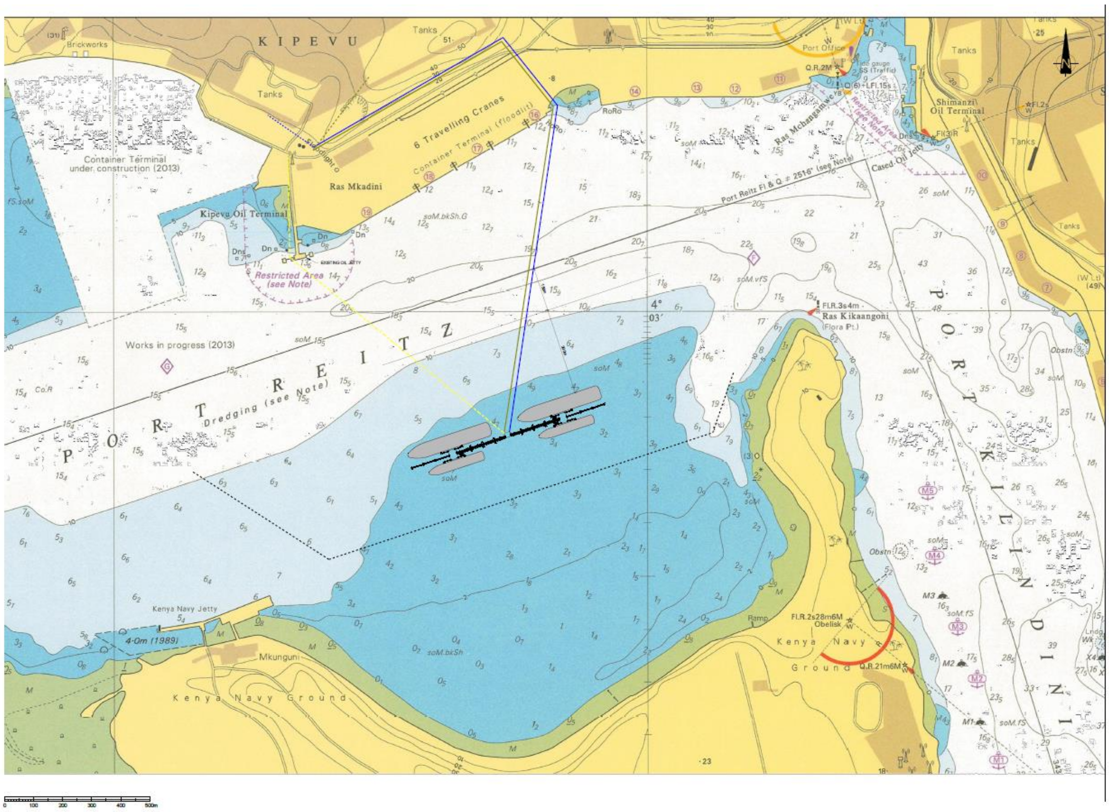
*Table F – 17: Schedule of petroleum products for Kenya – millions litres*

| KENYA DOMESTIC PETROLEUM PRODUCT DEMAND 2000 TO 2040 BASE CASE | | | | | | | | KENYA DOMESTIC PETROLEUM PRODUCT DEMAND 2000 TO 2040 HIGH CASE | | | | | | | | KENYA DOMESTIC PETROLEUM PRODUCT DEMAND 2000 TO 2040 LOW CASE | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Petrol | Diesel | Kerosene | Jet | LPG | Fuel Oil | Total | ML | Petrol | Diesel | Kerosene | Jet | LPG | Fuel Oil | Total | ML | Petrol | Diesel | Kerosene | Jet | LPG | Fuel Oil | Total |
| **2000** | 494 | 883 | 384 | 432 | 62 | 522 | 2777 | **2000** | 494 | 883 | 384 | 432 | 62 | 522 | 2777 | **2000** | 494 | 883 | 384 | 432 | 62 | 522 | 2777 |
| **2001** | 506 | 824 | 306 | 417 | 66 | 594 | 2713 | **2001** | 506 | 824 | 306 | 417 | 66 | 594 | 2713 | **2001** | 506 | 824 | 306 | 417 | 66 | 594 | 2713 |
| **2002** | 494 | 781 | 274 | 470 | 75 | 531 | 2625 | **2002** | 494 | 781 | 274 | 470 | 75 | 531 | 2625 | **2002** | 494 | 781 | 274 | 470 | 75 | 531 | 2625 |
| **2003** | 442 | 793 | 195 | 487 | 75 | 439 | 2432 | **2003** | 442 | 793 | 195 | 487 | 75 | 439 | 2432 | **2003** | 442 | 793 | 195 | 487 | 75 | 439 | 2432 |
| **2004** | 462 | 979 | 306 | 676 | 77 | 503 | 3003 | **2004** | 462 | 979 | 306 | 676 | 77 | 503 | 3003 | **2004** | 462 | 979 | 306 | 676 | 77 | 503 | 3003 |
| **2005** | 465 | 1082 | 390 | 711 | 90 | 625 | 3362 | **2005** | 465 | 1082 | 390 | 711 | 90 | 625 | 3362 | **2005** | 465 | 1082 | 390 | 711 | 90 | 625 | 3362 |
| **2006** | 509 | 1267 | 364 | 752 | 119 | 760 | 3771 | **2006** | 509 | 1267 | 364 | 752 | 119 | 760 | 3771 | **2006** | 509 | 1267 | 364 | 752 | 119 | 760 | 3771 |
| **2007** | 512 | 1417 | 330 | 808 | 136 | 719 | 3922 | **2007** | 512 | 1417 | 330 | 808 | 136 | 719 | 3922 | **2007** | 512 | 1417 | 330 | 808 | 136 | 719 | 3922 |
| **2008** | 479 | 1460 | 285 | 706 | 144 | 640 | 3714 | **2008** | 479 | 1460 | 285 | 706 | 144 | 640 | 3714 | **2008** | 479 | 1460 | 285 | 706 | 144 | 640 | 3714 |
| **2009** | 598 | 1699 | 375 | 740 | 110 | 629 | 4152 | **2009** | 598 | 1699 | 375 | 740 | 110 | 629 | 4152 | **2009** | 598 | 1699 | 375 | 740 | 110 | 629 | 4152 |
| **2010** | 690 | 1610 | 323 | 748 | 118 | 607 | 4097 | **2010** | 690 | 1610 | 323 | 748 | 118 | 607 | 4097 | **2010** | 690 | 1610 | 323 | 748 | 118 | 607 | 4097 |
| **2011** | 781 | 1801 | 341 | 889 | 115 | 679 | 4606 | **2011** | 781 | 1801 | 341 | 889 | 115 | 679 | 4606 | **2011** | 781 | 1801 | 341 | 889 | 115 | 679 | 4606 |
| **2012** | 883 | 1907 | 401 | 851 | 118 | 450 | 4610 | **2012** | 883 | 1907 | 401 | 851 | 118 | 450 | 4610 | **2012** | 883 | 1907 | 401 | 851 | 118 | 450 | 4610 |
| **2013** | 1114 | 1992 | 390 | 699 | 110 | 358 | 4663 | **2013** | 1114 | 1992 | 390 | 699 | 110 | 358 | 4663 | **2013** | 1114 | 1992 | 390 | 699 | 110 | 358 | 4663 |
| **2014** | 1362 | 2108 | 393 | 730 | 115 | 348 | 5058 | **2014** | 1362 | 2108 | 393 | 730 | 115 | 348 | 5058 | **2014** | 1362 | 2108 | 393 | 730 | 115 | 348 | 5058 |
| **2015** | 1444 | 2252 | 397 | 763 | 121 | 337 | 5315 | **2015** | 1458 | 2252 | 401 | 767 | 123 | 330 | 5331 | **2015** | 1424 | 2232 | 405 | 752 | 119 | 348 | 5280 |
| **2020** | 1932 | 3321 | 418 | 951 | 155 | 290 | 7066 | **2020** | 2044 | 3331 | 443 | 979 | 168 | 256 | 7221 | **2020** | 1774 | 3020 | 470 | 872 | 138 | 348 | 6621 |
| **2025** | 2586 | 4974 | 439 | 1185 | 197 | 249 | 9630 | **2025** | 2867 | 5691 | 489 | 1249 | 231 | 198 | 10725 | **2025** | 2211 | 4120 | 545 | 1011 | 160 | 348 | 8394 |
| **2030** | 3460 | 7293 | 461 | 1477 | 252 | 214 | 13158 | **2030** | 4021 | 10270 | 540 | 1595 | 316 | 153 | 16895 | **2030** | 2755 | 5449 | 631 | 1172 | 185 | 348 | 10541 |
| **2035** | 4968 | 10409 | 473 | 1931 | 337 | 165 | 18283 | **2035** | 6187 | 18274 | 540 | 2185 | 454 | 90 | 27731 | **2035** | 3516 | 7021 | 732 | 1392 | 225 | 348 | 13234 |
| **2040** | 7132 | 14589 | 485 | 2523 | 451 | 128 | 25309 | **2040** | 9520 | 31976 | 540 | 2993 | 652 | 53 | 45734 | **2040** | 4487 | 8913 | 849 | 1654 | 274 | 348 | 16525 |
| AAI00- | 6.45% | 6.46% | 0.12% | 3.77% | 4.56% | -2.85% | 4.07% | AAI00-13 | 6.45% | 6.46% | 0.12% | 3.77% | 4.56% | -2.85% | 4.07% | AAI00-13 | 6.45% | 6.46% | 0.12% | 3.77% | 4.56% | -2.85% | 4.07% |
| AAI14- | 6.57% | 7.72% | 0.81% | 4.88% | 5.38% | -3.77% | 6.39% | AAI14-40 | 7.76% | 11.02% | 1.23% | 5.57% | 6.88% | -6.96% | 8.84% | AAI14-40 | 4.69% | 5.70% | 3.00% | 3.19% | 3.38% | 0.00% | 4.66% |

*Source: PwC Consortium*

# Appendix G. - Mombasa Port map

*Figure G- 1: Mombasa Port map with relocated Kipevu Oil Terminal*




*Source: KPA*

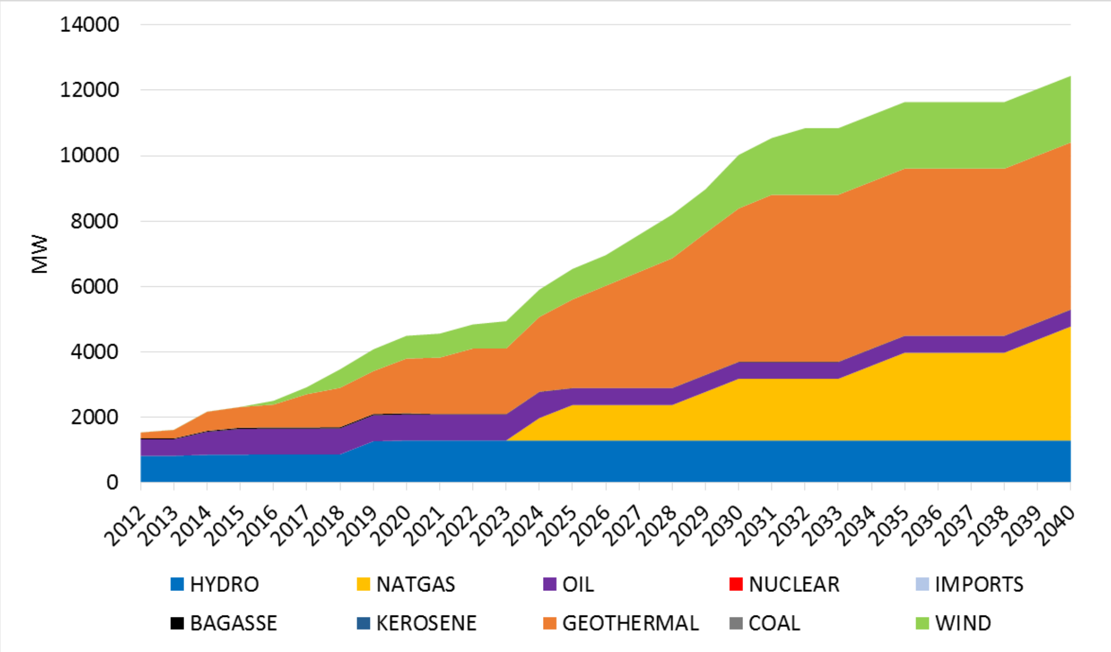
# Appendix H. - Base case scenario Demand for Gas-fired Power Generation

## Base case scenario

In the Base Case we assume all hydro, wind, oil-fired, geothermal projects that are currently expected to come online in our delayed 5000+MW plan view are realised taking power generation capacity from 1,885MW to just under 4,500MW by 2020. This includes the addition of 437MW of hydro, 1087MW of geothermal and 690MW of wind power generation. We assume the planned development of two coal-fired power plants with combined capacity of 2,300MW before 2020 does not occur as 1) despite providing reliable baseload supply, they may not be required from a demand perspective and 2) gas-fired power generation is likely to be a better option for the reasons discussed below.Post-2020, our assumptions are listed and shown in the figure below:

- Hydro: We assume no more hydro power generation is developed following the 437MW expected to be brought online before 2020.
- Oil-fired: Oil-fired power plants based in Mombasa (285MW) are converted to run on gas, leaving around 500MW (which has been added recently in the last 7 years) for consideration to be switched to gas if and when a gas supply network is developed in Kenya. No further oil-fired power plants are developed. This is much less than the 1,635MW by 2030 assumed in the LCPDP 2011.
- Imports: We assume no major power imports projects get developed. This is less than the 1,600MW of imports by 2025 and 2,000MW by 2030 assumed in the LCPDP.
- Wind: We have used assumptions made in the LCPDP albeit with a 2-3 year delay to reflect delays to current plans– steadily increasing to reach approximately 2,000MW by 2033.
- Geothermal: We have largely used assumptions made in the LCPDP with total capacity increasing from 1,674MW in 2020 (as currently expected) to just over 5,000MW by 2030. A target of 5,000MW by 2030 has also been expressed by the Kenyan Government. However, there are concerns that this may be overly optimistic, particularly as total geothermal capacity around the world is currently around 12,000MW.
- Coal: We assume no coal fired power generation is developed. With good potential for indigenous gas resources, gas-fired power generation is likely to be cheaper than import-based coal-fired power generation not to mention cleaner and more efficient.
- Nuclear: We assume no nuclear power generation is realised before 2040 due to significant challenges of developing and financing such projects.
- Gas: We assume 1,085MW of gas-fired power generation based on indigenous resources is developed around 2025, including switching 285MW from being oil-fired. This can be developed sooner depending on when indigenous production comes online. There is also a case to develop the initial plants earlier based on LNG imports. But this will ultimately also depend on demand. A further 800MW is assumed to be developed in each of the periods around 2030, 2035 and 2040, bringing total gas-fired power generation capacity to 1,885MW by 2030, 2,685MW by 2035 and 3,485MW by 2040.

*Figure H – 1: Power generation forecast – Base case*




*Source: PwC Consortium*

*Table H – 1: Power generation forecasts - Base case*

| MW | Hydro | Natgas | Oil | Nuclear | Imports | Bagasse | Kerosene | Geothermal | Coal | Wind | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2015** | 860 | 0 | 786 | 0 | 0 | 36 | 0 | 632 | 0 | 5 | **2320** |
| **2016** | 867 | 0 | 786 | 0 | 0 | 36 | 0 | 702 | 0 | 115 | **2507** |
| **2017** | 867 | 0 | 786 | 0 | 0 | 36 | 0 | 1019 | 0 | 215 | **2924** |
| **2018** | 867 | 0 | 796 | 0 | 0 | 36 | 0 | 1204 | 0 | 565 | **3469** |
| **2019** | 1267 | 0 | 796 | 0 | 0 | 36 | 0 | 1314 | 0 | 665 | **4079** |
| **2020** | 1292 | 0 | 796 | 0 | 0 | 36 | 0 | 1674 | 0 | 695 | **4494** |
| **2025** | 1292 | 1085 | 511 | 0 | 0 | 10 | 0 | 2708 | 0 | 935 | **6541** |
| **2030** | 1292 | 1885 | 511 | 0 | 0 | 10 | 0 | 4690 | 0 | 1636 | **10024** |
| **2035** | 1292 | 2685 | 511 | 0 | 0 | 10 | 0 | 5110 | 0 | 2036 | **11644** |
| **2040** | 1292 | 3485 | 511 | 0 | 0 | 10 | 0 | 5110 | 0 | 2036 | **12444** |

*Source: PwC Consortium*

Assuming a load factor of 60% and a thermal efficiency of 55%, gas requirements for in the Base Case would be approximately 1 Bcm/yr in 2025, rising to 1.8 Bcm/yr in 2030, 2.6 Bcm/yr in 2035 and to 3.3 Bcm/yr in 2040.

# *Low gas case scenario*

In the Low Case, as with the Base Case we assume all hydro, wind, oil-fired, geothermal projects that are currently expected to come online in our delayed 5000+MW plan view are realized. This includes the addition of 437MW of hydro, 1087MW of geothermal and 690MW of wind power generation. We further assume that the planned development of two coal-fired power plants with combined capacity of 2,300MW before 2020 also occurs taking power generation capacity from 1,885MW to just under 6,800MW by 2020 – and hence the full 5000+MW plan is realized by 2020.

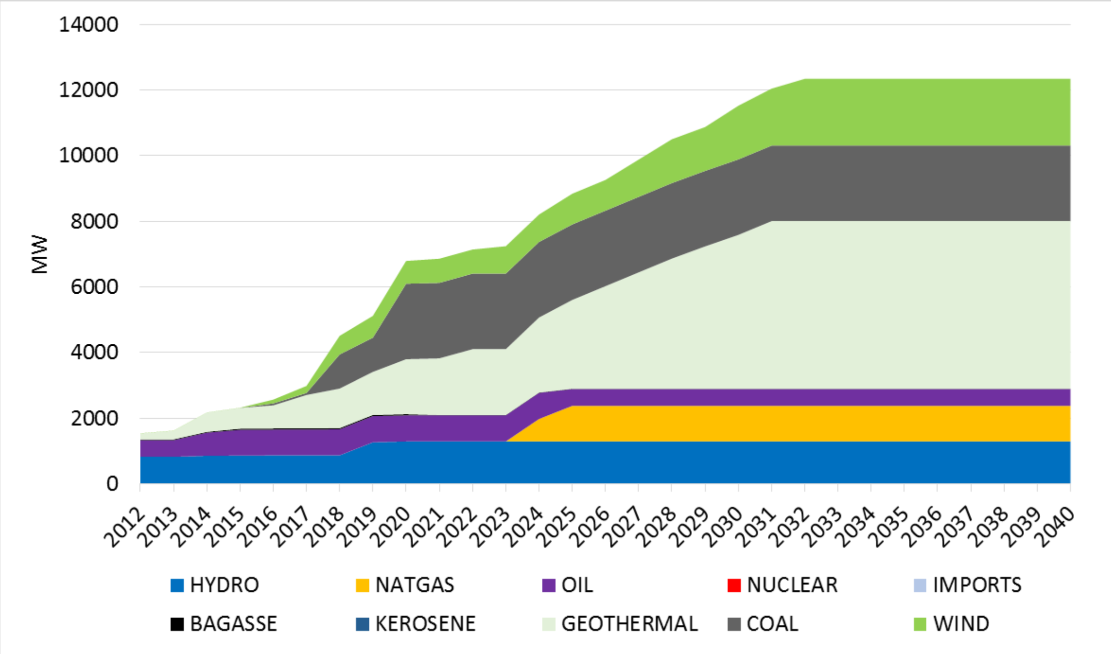
Post-2020, our assumptions are listed below. Key changes to the Low Case as compared to the Base Case is that gas-fired power generation is realized to a lesser extent. The following assumptions are the same as in the Base Case:

- Hydro: We assume no more hydro power generation is developed following the 437MW expected to be brought online before 2020.
- Oil-fired: Oil-fired power plants based in Mombasa (285MW) are converted to run on gas, leaving around 500MW (which has been added recently in the last 7 years) for consideration to be switched to gas if and when a gas supply network is developed in Kenya. No further oil-fired power plants are developed. This is much less than the 1,635MW by 2030 assumed in the LCPDP 2011.
- Imports: We assume no major power imports projects get developed. This is less than the 1,600MW of imports by 2025 and 2,000MW by 2030 assumed in the LCPDP.
- Wind: We have used assumptions made in the LCPDP albeit with a 2-3 year delay to reflect delays to current plans– steadily increasing to reach approximately 2,000MW by 2033.
- Nuclear: We assume no nuclear power generation is realised before 2040 due to significant challenges of developing and financing such projects.
- Geothermal: We have largely used assumptions made in the LCPDP with total capacity increasing from 1,674MW in 2020 (as currently expected) to just over 5,000MW by 2030.

Changes to the Base Case assumptions are as follows:

- Coal: We assume that the planned development of two coal-fired power plants are realized in 2018 and 2020 as currently expected with combined capacity of 2,300MW. We assume no more coal-fired power generation gets developed post 2020. The 2,300MW is fairly close to LCPDP projections of 2,420MW by 2030.
- Gas: We assume 1,085MW of gas-fired power generation based on indigenous resources is developed sometime after 2025, including switching 285MW from being oil-fired. We assume no further gas-fired power generation is developed after this.

*Figure H – 2: Power generation forecast – Low case*




*Source: PwC Consortium*

*Table H - 2: Power generation forecasts - Low case*

| MW | Hydro | Gas | Oil | Nuclear | Imports | Bagasse | Kerosene | Geothermal | Coal | Wind | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2015** | 860 | 0 | 786 | 0 | 0 | 36 | 0 | 632 | 0 | 5 | **2320** |
| **2016** | 867 | 0 | 786 | 0 | 0 | 36 | 0 | 702 | 60 | 115 | **2567** |
| **2017** | 867 | 0 | 786 | 0 | 0 | 36 | 0 | 1019 | 60 | 215 | **2984** |
| **2018** | 867 | 0 | 796 | 0 | 0 | 36 | 0 | 1204 | 1042 | 565 | **4511** |
| **2019** | 1267 | 0 | 796 | 0 | 0 | 36 | 0 | 1314 | 1042 | 665 | **5121** |
| **2020** | 1292 | 0 | 796 | 0 | 0 | 36 | 0 | 1674 | 2302 | 695 | **6796** |
| **2025** | 1292 | 1085 | 511 | 0 | 0 | 10 | 0 | 2708 | 2302 | 935 | **8843** |
| **2030** | 1292 | 1085 | 511 | 0 | 0 | 10 | 0 | 4690 | 2302 | 1636 | **11526** |
| **2035** | 1292 | 1085 | 511 | 0 | 0 | 10 | 0 | 5110 | 2302 | 2036 | **12346** |
| **2040** | 1292 | 1085 | 511 | 0 | 0 | 10 | 0 | 5110 | 2302 | 2036 | **12346** |

*Source: PwC Consortium*

Assuming a load factor of 60% and a thermal efficiency of 55%, gas requirements in the Low Case would be flat at approximately 1 Bcm/yr in 2025 through to 2040.

# *High gas case scenario*

In the High Case, as with the Base Case we assume all hydro, wind, oil-fired, geothermal projects that are currently expected to come online in our delayed 5000+MW plan view are realised taking power generation capacity from 1,885MW to just under 4,500MW by 2020. This includes the addition of 437MW of hydro, 1087MW of geothermal and 690MW of wind power generation. We assume the planned development of two coal-fired power plants with combined capacity of 2,300MW before 2020 does not occur as 1) despite providing reliable baseload supply, they may not be required from a demand perspective and 2) gas-fired power generation is likely to be a better option for the reasons discussed below.

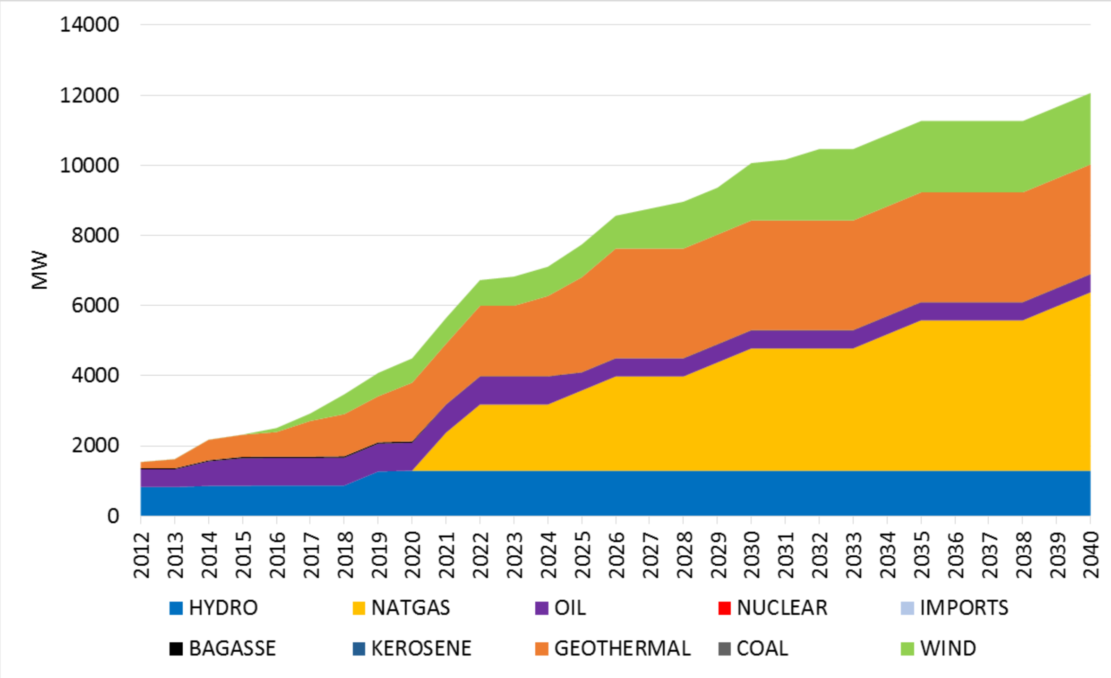
Post-2020, our assumptions are listed below. Key changes to the High Case as compared to the Base Case is that geothermal power generation is realized to a lesser extent. The following assumptions are the same as in the Base Case:

- Hydro: We assume no more hydro power generation is developed following the 437MW expected to be brought online before 2020.
- Oil-fired: Oil-fired power plants based in Mombasa (285MW) are converted to run on gas, leaving around 500MW (which has been added recently in the last 7 years) for consideration to be switched to gas if and when a gas supply network is developed in Kenya. No further oil-fired power plants are developed. This is much less than the 1,635MW by 2030 assumed in the LCPDP 2011.
- Imports: We assume no major power imports projects get developed. This is less than the 1,600MW of imports by 2025 and 2,000MW by 2030 assumed in the LCPDP.
- Wind: We have used assumptions made in the LCPDP albeit with a 2-3 year delay to reflect delays to current plans– steadily increasing to reach approximately 2,000MW by 2033.
- Coal: We assume no coal fired power generation is developed. With good potential for indigenous gas resources, gas-fired power generation is likely to be cheaper than import-based coal-fired power generation not to mention cleaner and more efficient.
- Nuclear: We assume no nuclear power generation is realized before 2040 due to significant challenges of developing and financing such projects.

Changes to the Base Case assumption are as follows:

- Geothermal: We have assumed geothermal occurs to a lesser extent than projected in the LCPDP with total capacity increasing from 1,674MW in 2020 (as currently expected) to just over 3,000MW by 2030.
- Gas: We assume 1,885MW of gas-fired power generation is developed earlier than in the Base Case around 2021-2022, including switching 285MW from being oil-fired, and is initially based on LNG imports. A further 800MW is assumed to be developed in each of the periods around 2025, 2030, 2035 and 2040, bringing total gas-fired power generation capacity to 2,285MW by 2025, 3,485MW by 2030, 4,285MW by 2035 and 5,085MW by 2040. LNG imports are assumed to be replaced by indigenous gas supply by the time additional power plants are developed around 2025.

*Figure H – 3: Power generation forecast – High case*




*Source: PwC Consortium*

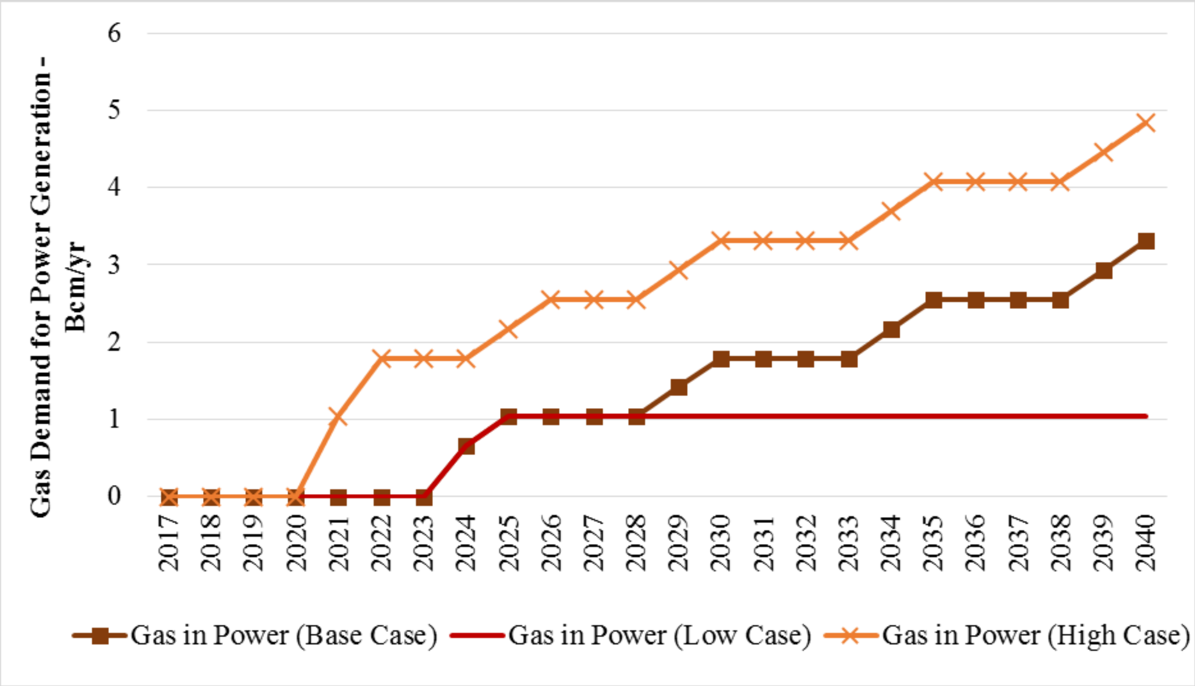
*Table H – 3: Power generation forecasts - High case*

| MW | Hydro | Gas | Oil | Nuclear | Imports | Bagasse | Kerosene | Geothermal | Coal | Wind | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **2015** | 860 | 0 | 786 | 0 | 0 | 36 | 0 | 632 | 0 | 5 | **2320** |
| **2016** | 867 | 0 | 786 | 0 | 0 | 36 | 0 | 702 | 0 | 115 | **2507** |
| **2017** | 867 | 0 | 786 | 0 | 0 | 36 | 0 | 1019 | 0 | 215 | **2924** |
| **2018** | 867 | 0 | 796 | 0 | 0 | 36 | 0 | 1204 | 0 | 565 | **3469** |
| **2019** | 1267 | 0 | 796 | 0 | 0 | 36 | 0 | 1314 | 0 | 665 | **4079** |
| **2020** | 1292 | 0 | 796 | 0 | 0 | 36 | 0 | 1674 | 0 | 695 | **4494** |
| **2025** | 1292 | 2285 | 511 | 0 | 0 | 10 | 0 | 2708 | 0 | 935 | **7741** |
| **2030** | 1292 | 3485 | 511 | 0 | 0 | 10 | 0 | 3128 | 0 | 1636 | **10062** |
| **2035** | 1292 | 4285 | 511 | 0 | 0 | 10 | 0 | 3128 | 0 | 2036 | **11262** |
| **2040** | 1292 | 5085 | 511 | 0 | 0 | 10 | 0 | 3128 | 0 | 2036 | **12062** |

*Source: PwC Consortium*

Assuming a load factor of 60% and a thermal efficiency of 55%, gas requirements in the High Case would be approximately 1.8 Bcm/yr in 2022, rising to 2.2 Bcm/yr in 2025, 3.3 Bcm/yr in 2030, 4.1 Bcm/yr in 2035 and 4.8 Bcm/yr in 2040.

*Figure H – 4: Gas demand in power generation – all scenarios*




*Source: PwC Consortium*

# Appendix I. - Generally Accepted Principles and Practices (GAPP)—Santiago Principles

In furtherance of the "Objective and Purpose," the IWG members either have implemented or intend to implement the following principles and practices, on a voluntary basis, each of which is subject to home country laws, regulations, requirements and obligations. This paragraph is an integral part of the GAPP.

**GAPP 1. Principle:**

The legal framework for the SWF should be sound and support its effective operation and the achievement of its stated objective(s).

GAPP 1.1. Subprinciple: The legal framework for the SWF should ensure legal soundness of the SWF and its transactions.

GAPP 1.2. Subprinciple: The key features of the SWF's legal basis and structure, as well as the legal relationship between the SWF and other state bodies, should be publicly disclosed.

**GAPP 2. Principle:**

The policy purpose of the SWF should be clearly defined and publicly disclosed.

**GAPP 3. Principle:**

Where the SWF's activities have significant direct domestic macroeconomic implications, those activities should be closely coordinated with the domestic fiscal and monetary authorities, so as to ensure consistency with the overall macroeconomic policies.

**GAPP 4. Principle:**

There should be clear and publicly disclosed policies, rules, procedures, or arrangements in relation to the SWF's general approach to funding, withdrawal, and spending operations.

GAPP 4.1. Subprinciple: The source of SWF funding should be publicly disclosed.

GAPP 4.2. Subprinciple: The general approach to withdrawals from the SWF and spending on behalf of the Government should be publicly disclosed.

**GAPP 5. Principle:**

The relevant statistical data pertaining to the SWF should be reported on a timely basis to the owner, or as otherwise required, for inclusion where appropriate in macroeconomic data sets.

**GAPP 6. Principle:**

The governance framework for the SWF should be sound and establish a clear and effective division of roles and responsibilities in order to facilitate accountability and operational independence in the management of the SWF to pursue its objectives.

**GAPP 7. Principle:**

The owner should set the objectives of the SWF, appoint the members of its governing body (ies) in accordance with clearly defined procedures, and exercise oversight over the SWF's operations.

**GAPP 8. Principle:**

The governing body (ies) should act in the best interests of the SWF, and have a clear mandate and adequate authority and competency to carry out its functions.

**GAPP 9. Principle:**

The operational management of the SWF should implement the SWF's strategies in an independent manner and in accordance with clearly defined responsibilities.

**GAPP 10. Principle:**

The accountability framework for the SWF's operations should be clearly defined in the relevant legislation, charter, other constitutive documents, or management agreement.

**GAPP 11. Principle:**

An annual report and accompanying financial statements on the SWF's operations and performance should be prepared in a timely fashion and in accordance with recognized international or national accounting standards in a consistent manner.

**GAPP 12. Principle:**

The SWF's operations and financial statements should be audited annually in accordance with recognized international or national auditing standards in a consistent manner.

**GAPP 13. Principle:**

Professional and ethical standards should be clearly defined and made known to the members of the SWF's governing body (ies), management, and staff.

**GAPP 14. Principle:**

Dealing with third parties for the purpose of the SWF's operational management should be based on economic and financial grounds, and follow clear rules and procedures.

**GAPP 15. Principle:**

SWF operations and activities in host countries should be conducted in compliance with all applicable regulatory and disclosure requirements of the countries in which they operate.

**GAPP 16. Principle:**

The governance framework and objectives, as well as the manner in which the SWF's management is operationally independent from the owner, should be publicly disclosed.

**GAPP 17. Principle:**

Relevant financial information regarding the SWF should be publicly disclosed to demonstrate its economic and financial orientation, so as to contribute to stability in international financial markets and enhance trust in recipient countries.

**GAPP 18. Principle:**

The SWF's investment policy should be clear and consistent with its defined objectives, risk tolerance, and investment strategy, as set by the owner or the governing body(ies), and be based on sound portfolio management principles.

GAPP 18.1. Subprinciple: The investment policy should guide the SWF's financial risk exposures and the possible use of leverage.

GAPP 18.2. Subprinciple: The investment policy should address the extent to which internal and/or external investment managers are used, the range of their activities and authority, and the process by which they are selected and their performance monitored.

GAPP 18.3. Subprinciple: A description of the investment policy of the SWF should be publicly disclosed.

**GAPP 19. Principle:**

The SWF's investment decisions should aim to maximize risk-adjusted financial returns in a manner consistent with its investment policy, and based on economic and financial grounds.

GAPP 19.1. Subprinciple: If investment decisions are subject to other than economic and financial considerations, these should be clearly set out in the investment policy and be publicly disclosed.

GAPP 19.2. Subprinciple: The management of an SWF's assets should be consistent with what is generally accepted as sound asset management principles.

**GAPP 20. Principle:**

The SWF should not seek or take advantage of privileged information or inappropriate influence by the broader Government in competing with private entities.

**GAPP 21. Principle:**

SWFs view shareholder ownership rights as a fundamental element of their equity investments' value. If an SWF chooses to exercise its ownership rights, it should do so in a manner that is consistent with its investment policy and protects the financial value of its investments. The SWF should publicly disclose its general approach to voting securities of listed entities, including the key factors guiding its exercise of ownership rights.

**GAPP 22. Principle:**

The SWF should have a framework that identifies, assesses, and manages the risks of its operations.

GAPP 22.1. Subprinciple: The risk management framework should include reliable information and timely reporting systems, which should enable the adequate monitoring and management of relevant risks within acceptable parameters and levels, control and incentive mechanisms, codes of conduct, business continuity planning, and an independent audit function.

GAPP 22.2. Subprinciple: The general approach to the SWF's risk management framework should be publicly disclosed.

**GAPP 23. Principle:**

The assets and investment performance (absolute and relative to benchmarks, if any) of the SWF should be measured and reported to the owner according to clearly defined principles or standards.

**GAPP 24. Principle:**

A process of regular review of the implementation of the GAPP should be engaged in by or on behalf of the SWF.

# Appendix J. - Environmental and Social Concerns

## Introduction

This section gives a general overview of the Kenyan environment and the potential negative impacts on it as a result of petroleum exploration and development activities, in addition to the infrastructural development identified in the oil commercialization and gas monetization options as part of this Study. It is envisaged that a more comprehensive Strategic Environmental and Social Assessment (SESA) will be undertaken in the short term as recommended in this Study. This will not only specify key impacts that need to be addressed but also develop a comprehensive Environmental and Social Environmental Management Plan for the sector. The proposed SESA should also include an assessment of (i) environmental and social risks and impacts; (ii) involuntary resettlement; (iii) loss of income and livelihood; and (iv) occupational, health and safety aspects in petroleum operations. Public participation in all these four areas potential for exploration and development and associated infrastructure will be critical during the SESA process.

It is important to note that "environment" is a broad term that represents the totality of the surrounding area such as plants, animals, microorganisms, socio economic and cultural factors. It includes the physical factors of the surroundings of human beings such as land, water, atmosphere, sound, odour, the biological factors of animals and plants, and the social factors of aesthetics across both the natural and the built environment.

Kenya has significant biodiversity and enjoys a unique tropical climate with varying weather patterns due to differing topographical dimensions. The country has a wide variety of ecosystems namely mountains, forests, arid and semi-arid areas (ASALs), freshwater, wetlands, coastal and marine areas, all offering many opportunities for sustainable human, social and economic development. These ecosystems are natural capitals which provide important regulatory services (such as forests and mountains which regulate water flow and sustain biodiversity), provision services (for example forests providing timber and fuel wood), cultural services (such as aesthetic, recreational or spiritual values and uses) and supporting services (like soil formation, nutrient cycling and primary production).

The survival and socio-economic wellbeing of Kenyans is ultimately intertwined with the environment. Most Kenyan citizens depend directly or indirectly on environmental goods and services. In addition, Kenya's environmental resources contribute directly and indirectly to the local and national economies through revenue generation and wealth creation in sectors such as agriculture (including fisheries and livestock), water, energy, forestry, trade, tourism and manufacturing.

The promulgation of the Constitution of Kenya 2010 marked an important chapter in Kenya's environmental policy development in the context of climate change. Hailed as a 'Green' Constitution, it includes elaborate provisions with considerable implications for sustainable development. These range from environmental principles and implications of Multilateral Environmental Agreements (MEAs), to the right to a clean and healthy environment as enshrined in the Bill of Rights. Chapter V of the Constitution is entirely dedicated to land and the environment. It also incorporates a host of social and economic rights which are of environmental character such as the right to water, food, and shelter, among others.

Kenya has fairly adequate Environmental and ESIA policies and legal frameworks. However much of the emphasis is on project approval processes, rather than on a life cycle approach to minimizing environmental and social impacts. Environmental monitoring and project follow-up are considered part of the ESIA. Nevertheless, in most cases actual enforcement is inadequate, environmental monitoring is insufficient and monitoring data is not widely disclosed to the public and affected stakeholders. Moreover, most counties have insufficient control and enforcement mechanisms during the post-ESIA approval phase due to limited human, technical and financial capacity.

## Background to Petroleum and its Environmental and Social Impacts

Impacts associated with the oil and gas sector vary by phase of the value chain, and include direct, indirect, and cumulative impacts. Oil and gas finds may occur on land, offshore, on continental shelves, deep sea, in Arid and Semi-Arid Lands ("ASALS"), wetlands, forests, animal parks and other fragile ecosystems.

Developing the oil and gas upstream and mid-stream industry is a challenge, considering the sensitivity of environmental issues in the country. The ongoing and planned upstream activities (exploration, production, decommissioning and restoration), mid-stream (transportation by pipeline, rail, oil tanker or truck, storage, and wholesale marketing of crude or refined petroleum products), and downstream activities (refining, distribution by tankers, retailing, and consumer networks for various petroleum products) are important for development of the country's petroleum industry value chain. In discussing the environmental concerns, the activities address different issues. Since commercial production of petroleum onshore is envisaged and offshore exploration is ongoing, the environmental concerns to be faced are terrestrial, atmospheric and marine in nature.

## Land, Land use, Urbanisation and Preservation of Cultural Resources

Land and natural resources occupy an important place in the political history, social organisation and economics of Kenya. A large proportion of the population lives in rural areas and derives their livelihood directly from the land. Of the total land surface area, approximately 17% is of high and medium potential while 83% is classified as ASALs. The Constitution of Kenya categorises land into three types: public, private and community land. Land concerns will be critical issues in the upstream oil and gas exploration activities in terms of expected displacements, resettlements, compensation, land-use changes, rapid unplanned urbanisation, and population immigration and growth. Limited mechanisms to preserve local cultural resources, national heritage, and archaeological and historic sites are key issues in areas with petroleum potential including parts of the Rift Valley, and in the Anza Graben and Coastal Lamu basins. Lokichar, Lamu, Mombasa, Nairobi, and other towns will experience growth in their populations due to the planned infrastructural facilities in these areas; resulting in more urbanization and land use issues. The old Lamu Port, lakes within the Rift Valley and the Lake Turkana National Park are designated as UNESCO World Heritage Sites, and adequate measures to ensure their preservation needs to be taken

## Threats to Forestry Resources

Key natural forests in Kenya include: mountain forests (Mt Kenya, the Aberdares, Mau, and the Kikuyu escarpment), dry zone forests (Marsabit, Taita hills and Namanga hills forests), western rain forests (Kakamega, Nandi and small patches of Nyanza and Western provinces), and coastal forests (Shimba hills and Arabuko Sokoke forests). Oil and gas upstream activities may have adverse impacts on forests, however at present most of the areas with oil and gas potential are in the ASALs of Kenya.

The country's ASALs, which cover about 80% of Kenya's total land surface and hold 25% of the human population are unique in nature and require special attention to strengthen not only the economic base of the inhabitants but also the national economy. Kenya's drylands, although rich in biodiversity are often stressed by frequent drought. Livestock keeping is the main economic activity of these drylands, and as a result adverse environmental impacts have a direct effect on the economic and social wellbeing of residents. However, due to population pressure in the high and medium agricultural potential areas, there is migration into the dryland areas resulting in depletion of grazing lands and forest resources as well as tree cover degradation. Currently, oil exploration is already taking place in the Arabuko Sokoke forest in the Coastal zone, and measures will need to be taken to ensure the forest is preserved.

Mangrove forests may also be affected in the event of oil spills from exploration, production and transportation activities especially the Lamu-Mombasa mangrove stretch. Mangrove forests are valued as carbon sinks in that they sequester a large quantity of carbon and therefore help in countering the effects of climate change. This is made possible through their high productivity and by also trapping carbon in biomass and below ground. The mangroves create a conducive habitat for inshore finfish and crustaceans. They also support highly productive offshore fisheries.

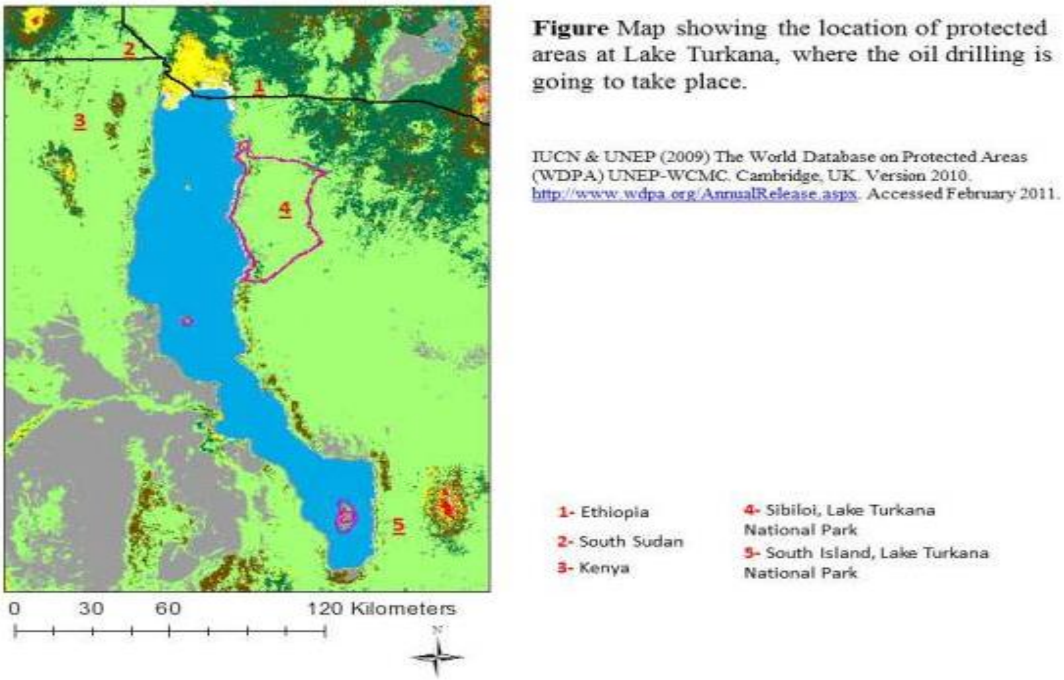
## Water and Wetland Resources Pollution

Kenya's principal rivers are the 710-kilometer-long Tana, and the Athi River, both flowing southeast to the Indian Ocean. Other rivers include the Ewaso Ngiro, flowing northeast to the swamps of the Lorian Plain, and the Nzoia, Yala, and Gori, which drain into Lake Victoria. The country shares a number of drainage basins with other countries: The Umba, Mara, and Pangani basins shared with the United Republic of Tanzania; The Sio, Malaba, and Malakisi basins shared with Uganda; The Omo and Daua basins shared with Ethiopia and the Nile basin shared with nine other countries. The main lakes include Turkana, Victoria, Baringo, Bogoria, Elementaita, Kanyaboli, Magadi, Naivasha and Nakuru. Lakes and rivers traversing through the oil and gas basins (East African Rift, Anza Graben, and Coastal Lamu) will have a significant risk of pollution. The water bodies at risk of impact include Lakes Turkana, Victoria, Baringo and Bogoria, the Indian Ocean, River Tana, and the Ewaso Ngiro River. Midstream and downstream infrastructure development may also put other water bodies at risk.

## *Impact on Fisheries and Livelihoods*

As stated above, the Republic of Kenya is endowed with vast water resources in the Indian Ocean, lakes, rivers and man-made dams and has fish production potential estimated at over 150,000 metric tonnes per year. According to the Kenya Fisheries Policy (2005), fisheries production contributes about 5% of the national GDP and supports the livelihood of over half a million Kenyans either directly or indirectly. About 96% of the total fish production is derived from fresh waters, while the Indian Ocean contributes the remaining 5%. Lake Victoria accounts for 71% of the country's total annual production. Lake Turkana (see the figure below), which is near Kenya's premier oil exploration zone, is Kenya's largest freshwater body (7,400 km2) and produces about 4,000MT of fish annually. Other freshwater bodies of commercial importance include Lake Naivasha, Baringo, and Jipe and the Tana River dams. The livelihoods of people who depend on these water bodies for their protein and employment will be risked in the event of pollution by petroleum related activities.

*Figure J – 1: Lake Turkana position near Kenya's premier oil exploration zone*




*Source: IUCN and UNEP, 2009*

## *Destruction of Wildlife Habitats*

Kenya's wildlife is one of the richest and most diversified in Africa with several of its protected areas and wetlands being internationally recognised and protected as World Heritage Sites, RAMSAR sites and Man and Biosphere Reserves. Kenya's wildlife resource also constitutes a unique natural heritage that is of great importance both nationally and globally. The Wildlife Policy (2007) indicate that wildlife and tourism accounts for about 25% of the country's GDP and more than 10% of total formal sector employment, though this is currently facing a threat due to increased insecurity. Wildlife also plays a critical ecological function that is important for the interconnected web of life supporting systems. Major impacts may include the destruction of terrestrial protected wildlife habitats due to upstream oil and gas exploration and production activities, and pollution of coastal and marine ecosystems such as coral reefs, mangrove forests and beaches, especially in the Lamu area due to offshore petroleum activities.

Kenya's four basins with petroleum prospects (Coastal Lamu, Anza Graben, Offshore and East African Tertiary Rift) with a total surface area of over 485,000km², and areas proposed for midstream infrastructure like pipelines, are the home to many wild animals (see the figure below). National Parks and Reserves are found within the gazetted petroleum blocks, and. these areas have unique flora and fauna, and scenic landscapes, which place them in strategic positions to benefit from ecotourism as well as the larger tourism industry. Environmental impact assessments and cost-benefit analyses in comparison with the tourism and ecotourism sectors should be taken into consideration through the EIA and CBA process in future investments options. Already, exploration in some areas near protected wildlife reserves and indigenous natural forests has generated protests from environmental groups since there is uncertainty and a lack of information on the potential environmental damage of such activity.

*Figure J – 2: Map of Kenya national parks & reserves*


*Source: KWS, 2014*

## *Coastal and Marine Resources*

The Kenyan coast features a diverse marine environment including estuaries, mangroves, sea grass beds, intertidal reef platforms and coral reefs that are vital for the diversity and reproduction of marine organisms. These are some of Kenya's most valuable ecosystems and they are protected by six marine national reserves and parks. The Kenyan coastal economy is highly dependent on natural resources on which various activities are based namely agriculture, maritime trade, tourism, fishing and mining among others. These resources also support various cultural and spiritual values of the local people.

The oil and gas exploration and production activities may negatively impact the coastal wetlands, coastal forests, mangrove swamps, coral reefs, tidal flats, beach/dunes, and marine fishery resources. The coastal environment is also at risk from marine transportation activities at the port and shipping along the coastline. The National Environmental Action Plan of 2008-2013 (GoK, 2008) estimated that at any given time, there are 50 ships on the major shipping lanes off the Kenyan coast, of which approximately 9 are oil tankers with capacities ranging from 50,000 to 250,000 metric tonnes. Most of this coastal tanker traffic passes 250 nautical miles off shore; however with Mombasa serving as the major port for Kenya as well as Uganda, Rwanda, Burundi, Eastern DRC and parts of Ethiopia, Southern Sudan, North Eastern Tanzania and Somalia, any major oil spill will likely have a big impact on the local economies. It should be noted that oil pollution may result from normal activities such as ship to shore transfers and upland tank storage at the port.

## *Biodiversity Threats*

Kenya is internationally recognised as a diverse country in terms of wealth of biodiversity. Biodiversity contributes to a wide variety of environmental services, such as regulation of the gaseous composition of the atmosphere, protection of the coastal zone, regulation of the hydrological cycle and climate, generation and conservation of fertile soils, dispersal and breakdown of wastes, pollination of many crops and absorption of pollutants. Human health and well-being are directly dependent on biodiversity. Biodiversity also provides genetic resources for food and agriculture and therefore constitutes the biological basis for food security and support for human livelihoods. Loss of biodiversity due to forest clearance for camps, exploration activities, infrastructural development (pipelines, airstrips, roads, railways, etc.), and pollution are likely impacts of the oil and gas sector's activities, and the SESA will need to advise on mitigation measures that can be employed to manage this impact.

## *Waste Management from Onshore and Offshore Developments*

Solid and liquid wastes generated during the exploration, development, and production of crude oil and gas include drilling fluids, muds, produced waters, cuttings, wastewater, sewage and sanitary waste and domestic waste. The characteristics of upstream, mid-stream and downstream waste will differ and will need different facilities and management systems. If these are not handled well, they will lead to water and environmental pollution in general.

## *Livestock Production*

Livestock rearing and production is the major activity in ASALs and contributes a considerable proportion of GDP and agricultural labour force. Oil exploration and production in ASALs may affect areas for grazing, and livestock corridors. It may also influence residents to abandon their traditional livestock-related lifestyles. This has already been reported in parts of Turkana County where oil has been discovered. This may in the long run change the dependence on traditional income and food sources to oil and gas-related exploration and production jobs and activities.

## *Climate Change Impacts*

Climate-resilient, low carbon development is a national priority for Kenya because it will support Kenya to absorb disturbances and build capacity to adapt to additional stress and change. By pursuing a green economy path and minimising carbon footprints, the country targets to deliver the constitutional right to a clean and healthy environment while minimising the country's contribution to global climate change. Air emissions from upstream, mid-stream and downstream petroleum activities will be a major environmental challenge to the country because it might change local micro-climatic conditions.

## *Petroleum Infrastructural Development and the Environment*

Petroleum industrial infrastructural development may include camps/ buildings, production sites, manufacturing facilities (such as natural gas processing facilities), power generation, refineries, roads, ports, railways, ICT infrastructure, pipelines, airports and electricity transmission. The environmental impacts of such infrastructural development are distinct and unique and include effects on flora and fauna, social and psychological disruption, vegetation clearance, excavation works and spillages during construction and operation. These impacts will be studied in detail during the SESA and individual ESIA project studies.

## Trans boundary Environmental Concerns

The ongoing Indian Ocean offshore exploration activities around Lamu are the main activities likely to have trans boundary concerns related to shared waters. Some trans boundary pollution from on shore and offshore oil and gas activities will have impacts at international and regional levels in terms of safety of offshore drilling activities and liability and compensation in case of accidents. Air emissions from potential oil refineries will also have regional and international concerns.

## *Emergency Preparedness and Disaster Management*

Communities are predisposed to disasters by a combination of factors such as poverty, aridity, settlement in areas with poor infrastructure and services such as informal urban settlements or even living in poorly constructed buildings. The country has experienced several downstream accidents and massive loss of lives both in urban and rural areas due to spillage from oil product pipelines and petrol tanker accidents. For example in January 2009, an oil spill ignition occurred near Molo, along the Nakuru-Kericho Highway and resulted in the death of at least 113 people and more than 200 critical injuries. Kenya's capacity to respond to emergencies and incidences is inadequate. However, OMC's through PIEA and the Oil Spill Mutual Aid Group (OSMAG) have equipment to handle mainly downstream oil spills and fire emergencies.

Recent global incidents in the petroleum sector that include the Trans-Israel Pipeline oil spill in December 2014, the North Dakota train collision in October, 2014, the Lac-Mégantic rail disaster in July 2013, the Little Buffalo oil spill in April 2011, the Deepwater Horizon drilling rig spill in the Gulf of Mexico in 2010, the Californian San Bruno pipeline explosion in 2010, the Pemex pipeline explosion in 2012, refinery fires and shutdowns such as the ones at BP Cherry Point, Chevron Richmond, and Amuay in Venezuela in 2012 — are strong reminders of the importance of emergency preparedness and are constantly influencing the activity of national and international regulators.

## *Petroleum Sector Security Concerns*

Security concerns have taken centre stage in both the Government and private sector circles since the August 1998 United States Embassy bombing in Nairobi's Central Business District that killed 213 and injured over 4,000 people. This is particularly due to the adverse impacts that threats to security have on business development and economic growth. Although the 1998 attacks were directed at the American Embassy, the vast majority of casualties were local citizens.

Since late 2011, Kenya has also seen an upsurge in frequent violent terrorist attacks on shopping malls / centres, churches, public transport vehicles and other forms of gatherings. Government officials believe that the attacks are being carried out by the Al-Shabaab terrorist group based out of Somalia in retaliation for *Operation Linda Nchi*, a coordinated military mission between the Somali National Army and the Kenyan military that began in October 2011, when troops from Kenya crossed the border into the conflict zones of southern Somalia. One major attack was on September 2013, where unidentified gunmen attacked the upmarket Westgate shopping mall in Nairobi. The siege, which lasted for about 4 days resulted in about 70 deaths and over 175 people were reportedly wounded in the mass shooting.

Mandera County in North East Kenya also experienced killings of over 60 people in a span of less than a month (November / December 2014). In July 2014, Lamu County experienced terror related executions of over 100 Kenyans. Several crime incidents are also on record in various parts of the country. One other historical non-terror related event was the 2007 post-election violence which resulted in approximately 1,500 deaths, mainly in the Rift Valley.

Due to the increased execution of terrorism related incidents and other forms of violent crimes mainly in Nairobi, Rift Valley, Northern, North Eastern, Lamu and Mombasa in the Coast, the petroleum industry stakeholders have become more alert to the need for effective mechanisms that assure Kenya's and the East Africa region's energy security. The security issue is also of importance since a number of incidents have been recorded in Kenya's prospective oil and gas sedimentary basins.

Security remains a major priority for the residents of areas with potential for upstream projects. At the village levels, security for homesteads and livestock is provided by heads of households. Village elders in collaboration with location chiefs often resolve domestic disputes, and their decisions are respected by the residents. All the villages have Kenya Police Reservists ("KPR") recruited and trained by the Kenya Police Service ("KPS"). However, some members of the local communities living in oil exploration areas feel that the KPR unit has prioritised protection of oil exploration installations at the expense of protecting them from criminals like cattle rustlers, bandits and militia from neighbouring communities or countries. In Turkana County in particular, there have been reports of residents converging on oil rig sites in an attempt to gain protection during inter-community raids. It is important for GoK to implement a strategy to ensure adequate resources are in place to ensure the security of both the local communities and upstream installations.

Cyber-crime is also on the rise in Kenya and globally. The world's largest oil producing company, Saudi Aramco, was the victim of a significant cyber-attack on August 15, 2012. The oil giant announced that 30,000 of its workstations had been infected by a virus. Moreover, on August 27 Qatar's natural gas pumper RasGas was hit by a similar attack, resulting in the company being taken offline for several days. Both Saudi Aramco and RasGas managed to limit the damage, as the attacks did not affect extraction or processing, but such a bold attack had important repercussions on the IT strategies of oil and gas organisations operating in the Middle East and the world at large.

Sharing information across the enterprise and where needed, with external stakeholders, requires security. Oil and gas companies operating in the country should invest in information security solutions enabling them to:

- Manage, archive, protect, authenticate, and scale their security systems and video surveillance information more effectively, increasing their capacity to detect, deter, and analyse security events in real time.
- Protect the integrity and confidentiality of information throughout its life cycle - no matter where it moves, who accesses it, or how it is used.
- Build reliable, efficient, and cost-effective data protection architecture to improve disaster recovery readiness, and simplify management.
- Development of a security and safety policy guideline or strategy for the oil and gas sector will be of critical importance due to the existing security situation areas with petroleum potential.

## *Community Perceptions*

Being located in ASAL regions of Kenya, most of the potential oil and gas zones face numerous socio-economic and political challenges. Among these are: high poverty levels, historical political marginalisation, low school enrolment levels, nomadic livestock husbandry; poor housing, limited access to health, water and sanitation facilities and services, lack of teaching aids and facilities, low transitional rates from primary to secondary schools, and early marriages leading to increased school dropout.

The majority of residents living in the town centres in these regions engage in small-scale businesses. The businesses range from jua kali (artisanship), retail, wholesale, catering, distribution, and rental housing. Others are kiosks, hardwares, bars, private clinics and chemists, entertainment establishments (pool halls and video shows), carpentry, and tailoring workshops. A high-level review of existing ESIA and Environmental Audit reports available from NEMA reveals a range of positive and negative impacts and perceptions as summarised below.

## *Positive Impacts and Expectations*

- Employment opportunities in the sector for both skilled and non-skilled labour from the community
- Provision of social amenities through CSR projects such as building classrooms and sanitary facilities for schools, and drilling of boreholes in the area;
- Creation of access roads in the area and thus improvement of the infrastructure in the area;
- Increased business opportunities and market creation for local goods;
- Technological transfers from skilled labourers to the unskilled labourers;
- Improved livelihoods of the community members who get job opportunities with oil and gas exploration companies, and support services companies;
- Improved levels of literacy in the community as a result of the bursaries and sponsorship programmes offered by investors; and,
- Urbanisation as a result of influx of people in the area in search of employment opportunities.

## *Negative impacts and perceptions*

- The proposed commercialization / monetization options could have adverse impacts on the health of community members if toxic gases and dust generated by vehicular traffic are released into the atmosphere.
- Displacement of community members from their ancestral lands.
- Discovery of oil might cause conflict among neighbouring communities if proper mechanisms are not put in place.
- Favouritism and nepotism during the recruitment process through the use of community social workers, politicians and local provincial administration.
- Increased vehicular traffic in the area would result in disturbance of livestock in their grazing areas.
- Loosening of soil and compaction in some areas as a result of movement of heavy trucks and machinery in the project area
- Interference with pastures which the community highly value due to their pastoralist culture.
- Felling of trees to pave way for access roads and the proposed test well drilling sites will destroy the already fragile ecosystem.
- Air pollution from exhaust emissions
- Gender imbalance in the oil and gas sector –men, women, youths and children may experience risks and benefits of the sector differently.
- Offshore pollution of fishing grounds in the deep sea.
- Increased accidents from pipelines and oil tankers.

The above perceptions imply that oil and gas companies setting up businesses in the country need to understand the social profile of these regions and integrate social issues into their operations for purposes of reducing risks and uncertainties. Integrating social issues into the planning process increases the likelihood of project success and gives a project a social licence to operate. There are several social risks related to the oil and gas sector. These include volatile economic growth, limited job creation, violent conflicts and business interruption, corruption, environmental degradation and pollution impacts to livelihoods, gender violence and discrimination, injuries to people, damage to assets and properties, and spread of HIV and AIDS among communities impacted by oil exploration, production, distribution and marketing outlets.

# Appendix K. - Financial Modelling Methodology

Both oil and gas financial models are designed to envelop two key characteristics:

1. Transparency – The architecture and calculations can be easily followed

2. Flexibility – The model can be readily updated in a timely and low risk manner.

We have applied best practice modelling techniques as set out in the table below, in developing the models.

*Table K - 1: Best practice modelling techniques*

| **Best Practice Modelling Techniques** |
| --- |
| • Separate input, calculation and output areas: this decreases the margin for error and reduces the complications for testing, and resolution of, errors. |
| • Conceptualise input and output areas need during the design phase, before we start modelling, taking full account of the particular requirements of our client. |
| • Clearly identify those cells in the input areas which actually drive the model. |
| • Keep it simple – break complex calculations down into simpler steps. This makes the model much easier for others to interpret and use, and for us to identify and eliminate any errors. The techniques we use make the model easier to interpret and they reduce the amount of work required if any of the calculations need to be changed in the future (as the change is made in one place). They will also have a direct impact on the speed at which the model calculates, thus improving efficiency of the model mechanics. |
| • Adequate "audit trail" of information so that the model is useful to those less familiar with it and not just another faceless spreadsheet. |
| • Include error checking mechanisms – this varies according to the complexity of the model, but could include for example input checks, consistency checks, output checks etc. |
| • Maintain consistency of time periods – we always agree up front the desired length of the accounting periods to be modelled and maintain this as constant throughout the model (e.g. annual, semi-annual, quarter or monthly). |
| • Keep positives positive and negatives negative – in our models we always show costs, cash outflows, or liabilities as negative and revenues, cash inflows, or assets as positives so that simple SUM statements may be used throughout the model. This greatly assists in interpretation particularly, for instance, in the odd circumstances where items that should be inflows are negative, or assets become liabilities. |

*Source: PwC Consortium*

# Oil Financial / Economic Model

**Methodology**

The objective of the Oil financial/economic model is to provide GoK with a tool to assess project economics for the various infrastructure options required to commercialise Kenya's oil discoveries as well as ensure an efficient product distribution and downstream system. In the case of the crude oil pipelines and refined product pipelines the model analyses the revenue required to make the system viable given various infrastructure options, financing packages, and timing, opex and capex assumptions. For the other infrastructure categories i.e. Refineries, and Storage, the model identifies capital costs and a debt repayment profile alone based on various financing sources available.

The table below lists the options analysed within the four infrastructure categories in the model (Crude Oil Pipelines, Product Pipelines, Refineries, and Storage):

*Table K – 2: Oil model options*

| Crude Oil Pipeline Options | Routing Options |
|---|---|
| **Crude Pipeline 1 - Common Pipeline Phase 1** | Lokichar to Lamu (LAPSSET) |
| | Lokichar - Eldoret - Mombasa (Southerly route) |
| | Lokichar-South of Lamu LAPSSET (Modified) |
| **Crude Pipeline 2 - Common Pipeline Phase 2** | Lokichar to Lamu (LAPSSET) |
| | Lokichar - Eldoret - Mombasa (Southerly route) |
| | Lokichar-South of Lamu LAPSSET (Modified) |
| **Crude Pipeline 3 (East Rift Connector to Lokichar)** | Turkana - Lokichar |
| | Routing B (Provision to analyse alternative routing options) |
| | Routing C (Provision to analyse alternative routing options) |
| **Crude Pipeline 4 (Lake Albert connector to Lokichar)** | Hoima - Lokichar |
| | Hoima- Eldoret- Mombasa |
| | Routing C (Provision to analyse alternative routing options) |
| **New Refined Product Pipeline Options** | Routing/Upgrade Phases |
| **Mombasa-Nairobi Product Pipeline** | Line 5 |
| | Line 5 upgrade |
| | Line X (planned by KPC for 2037) |
| **Nairobi - Nakuru Product Pipeline** | Line 4 upgrade |

| | |
|---|---|
| | Line 4 upgrade |
| **Sinendet - Kisumu** | Line7 |
| **Eldoret-Kampala (Uganda) Kigali (Rwanda)** | New Pipeline |
| | |
| **Nairobi to Nanyuki** | New Pipeline |
| **Lamu to Mombasa Hub** | New Pipeline |
| **Refinery Location Options** | Complexity Options |
| **Mombasa Refinery** | Hydroskimming Refinery |
| | Catcracking Refinery |
| | Coking Refinery |
| **Lamu Refinery** | Hydroskimming Refinery |
| | Catcracking Refinery |
| | Coking Refinery |
| **Storage Options** | |
| **Storage Conversion/Upgrade** | Mombasa Hub (assuming no refinery) |
| | KOSF |
| | Nairobi Airport |
| | Nakuru |
| | Eldoret |
| | Kisumu |
| | Nairobi Terminal |
| | Mombasa Airport |
| **Storage New Build Programme** | Mombasa (KPRL) |
| | Nairobi: Phase 1 |
| | Nairobi: Phase 2 |
| | Nairobi Airport |
| | Nairobi Rail Car for LPG |
| | Lokichar and Lamu Marine Terminal |

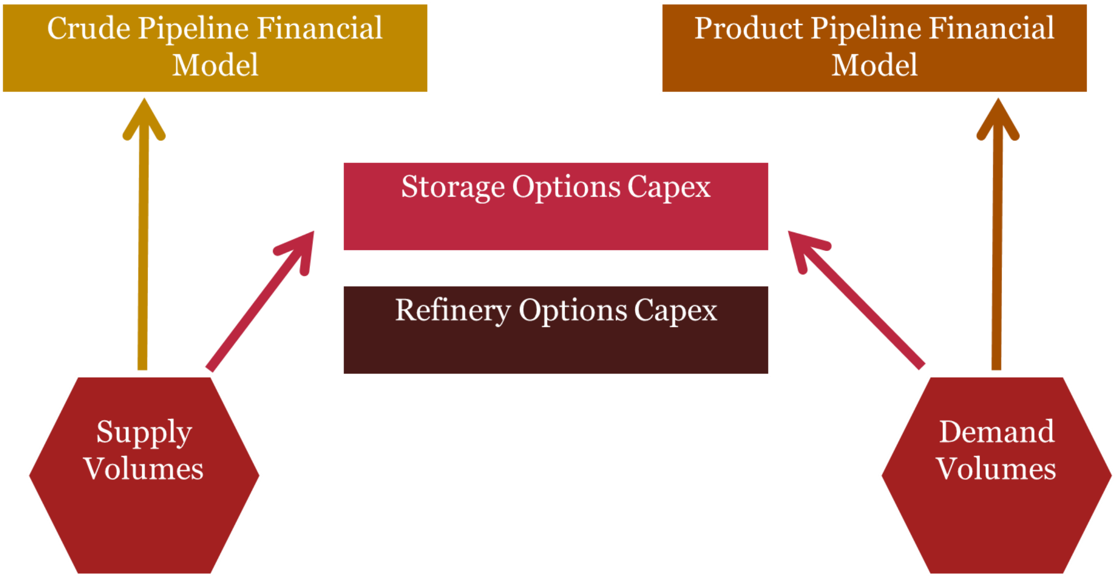
*Source: PwC Consortium*

Drawing from the review of Kenya's existing and planned oil infrastructure, the petroleum products demand analysis, and the potential crude supply estimates we developed a Financial Model ("The Model") that is built on the capital costs, operating costs, timing, financing and volume assumptions for the development of crude and products pipelines as defined earlier in this Report. The Model analyses the viability of the projects given the revenue required (in the case of the crude and product pipelines), in addition to carrying out an assessment of the funding required for the refinery, and storage options based on identified capital costs. To facilitate continued use by GoK, we have included functionalities to analyse additional options beyond the projects, routings and locations listed in the tables above. Provision is included to consider an additional:

- Crude pipeline and associated routing options,
- Product pipeline and associated routing options,
- Three Spur lines
- Two refinery options and associated location options
- Eight Storage facilities

The figure below illustrates the foundation blocks of the model:

*Figure K - 1: Oil financial/economic model building blocks*

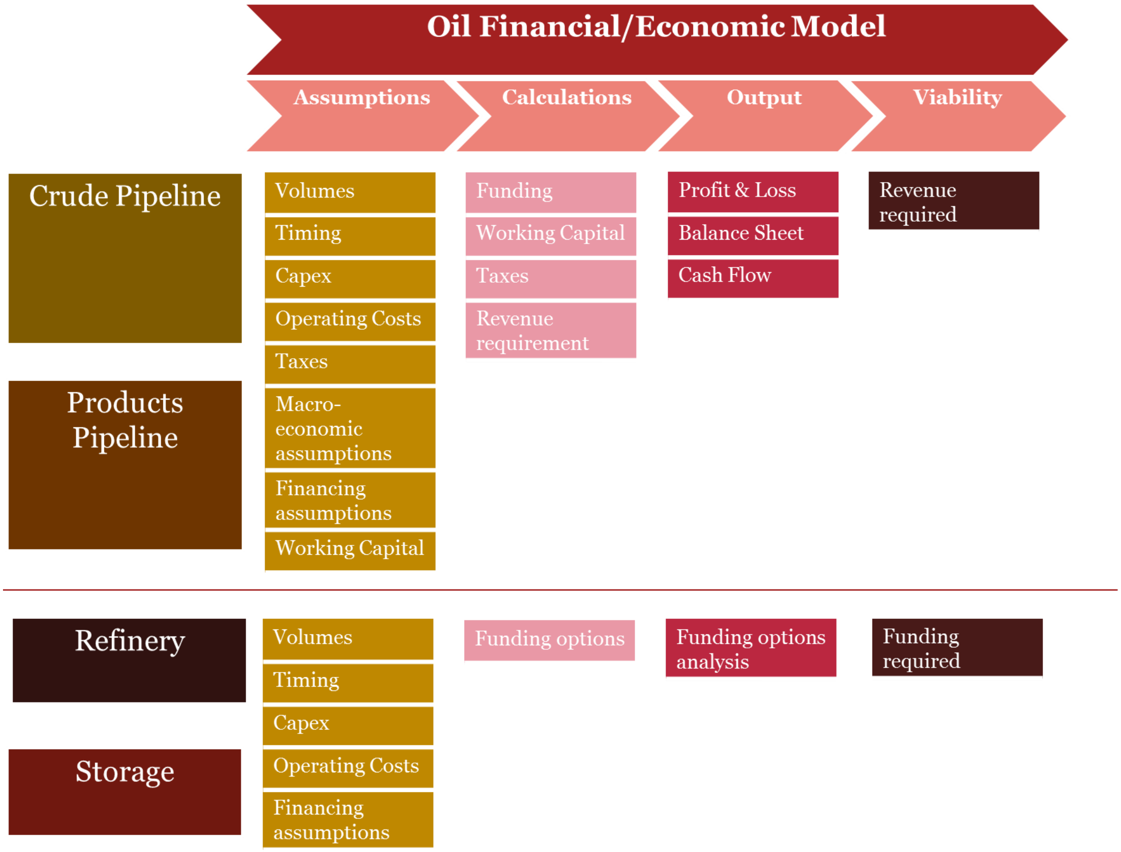



*Source: PwC Consortium*

*Note: For the refinery, and storage options, the model only considers the capital cost and funding repayment profile for each.*

The diagram shown in the figure below outlines the broad structure of the model and the associated relationship between the input, calculation and evaluation sheets driven by our viability analysis.

*Figure K – 2: Financial model structure*




*Source: PwC Consortium*

The model is structured to separate assumptions, calculations, outputs and analysis for each of the following:

- **Crude Pipelines**
- **Product Pipelines**
- **Refinery**
- **Storage**

These are then further analysed for each option identified above.

## Key Financial Metrics and Assumptions

### Key Financial Metrics

There are a number of financial metrics the model adopts in order to determine the revenue required for the viability of each option:

**Internal Rate of Return**: Each of the options analysed in the Financial Model has been structured to ensure an Equity IRR of 15% in US$ terms to each entity (this assumption can be varied).

**Overall cash flow**: We considered the real (projected) cash flows of each option to understand whether there are any periods in which an overdraft occurs, to ensure the funding options have been optimised for each entity.

**Revenue required**: The revenue required refers to a cost reflective fee for the crude oil pipeline and the refined products pipeline, and is designed to capture the following costs in addition to attaining the 15% equity return to the assets:

- Debt Repayment
- Interest and Finance Costs
- Operating Costs
- Taxes

## Step 1: Assumptions

### Timing

- Model Start Date – 2015
- Projection Period – 26 Years (up to 2040, including construction period)

### Macroeconomic Assumptions

#### *Currency and exchange rates*

All monetary values are stated in US dollar terms unless otherwise stated. Reference to Kenya Shillings (KES) has been made at a translation into US dollars at [US$ 1 = KES 89.16]. *(http://www.oanda.com/currency/converter/, 1 December 2014)*. However there are no inputs in KES.

#### *Inflation*

The model is represented in real terms over the Projection Period.

### Accounting Assumptions

The model has been constructed to give financial reporting consistent with International Financial Reporting Standards as displayed in integrated financial statements comprising income statement, cash flow statement and balance sheet.

### Volume, Capital and Operating Costs

The model is based on the volumes, capital and operating costs as defined early in this Report and determined as a result of the technical review, i.e. review of Kenya's existing and planned oil infrastructure, the demand analysis and the supply estimates. Based on this it analyses the revenue required for viability.

### Financing Assumptions

For each asset we have assumed a set of financing assumptions, based on the prevailing indicative Development Finance Institution (DFI), Commercial Bank and Concessional Financing funding terms that have been seen on infrastructure type finance raising projects within the region. The model allows for a funding mix comprising of one or more debt options. Provision for comparison of two additional financing options has also been made in the model.

We present in the table below the financing assumptions for the crude pipeline company. These are illustrative of the assumptions used for the other infrastructure categories (product pipeline, refinery, and storage).

*Table K – 3: Financing assumptions*

| Funding | Source | Units | | | | |
|---|---|---|---|---|---|---|
| **Crude Pipeline** | | | | | | |
| **Debt** | | | Development Finance Institutions | Commercial | Concessional | Refinancing of Commercial Debt |
| Gearing (Debt: Equity) | 70% | % | | | | |
| Senior Loan | OK | % | 75% | 25% | 0% | ON |
| Senior Loan (Proportion total funding) | | % | 52.5% | 17.5% | 0.0% | |
| Tenor | | Yrs | 15 Yr(s) | 7 Yr(s) | 25 Yr(s) | 5 Yr(s) |
| Base Rate (6 month Libor) | | % | 0.40% | 0.40% | 0.40% | 0.32% |
| Front-end Fee | | | 1.25% | 1.25% | 0.00% | 0.00% |
| Arrangement fee | | % | 0.25% | 1.50% | 0.50% | 1.50% |
| Commitment fee | | % | 1.00% | 2.00% | 0.00% | 2.00% |
| Interest Margin | | % | 5.00% | 6.50% | 1.00% | 7.50% |
| All in Interest Rate | | % | 5.40% | 6.90% | 1.40% | 7.82% |
| Term | | | | | | |
| From | | Year | 2016 | 2016 | 2016 | 2023 |
| Tenor | | Yrs | 15 Yr(s) | 7 Yr(s) | 25 Yr(s) | 5 Yr(s) |
| Grace Period End | | Year | 2020 | 2018 | 2027 | 2024 |
| Grace Period Equal to: | | Yrs | 3 Yr(s) | 1 Yr(s) | 10 Yr(s) | 0 Yr(s) |
| End | | Year | 2031 | 2023 | 2041 | 2028 |
| **Equity** | | | | | | |
| Proportion of Equity | | % | 30% | | | |
| Drawing Method | | | Prorate | | | |
| Equity Injection | | | | | | |
| Share Capital | | % | 100% | | | |

*Source: PwC Consortium*

## Other Assumptions

1. Taxes
   - Corporate tax = 30%
   - Tax losses = Carry forward for 4 years
2. Depreciation

An implied depreciation rate for each project is calculated based on the Estimated Useful Life of each infrastructure category.

*Table K – 4: Depreciation Rates*

| Depreciation | Estimated Useful Life | Implied Depreciation Rate |
|---|---|---|
| **Pipeline** | | |
| Crude Pipeline | 20 Yr(s) | 5.00% |
| Products Pipeline | 20 Yr(s) | 5.00% |
| Spur Line | 20 Yr(s) | 5.00% |
| **Refinery** | 20 Yr(s) | 5% |
| **Storage** | 20 Yr(s) | 5.00% |

*Source: PwC Consortium*

### Step 2: Calculations

In this section, we discuss three key calculations that will build up to the revenue requirement for each asset (infrastructure category).

**Revenue Requirement**

The Revenue Requirement is determined based on a 'cost reflective' approach. As such, we have calculated each asset's revenue stream based on three components:

1. *Revenue required to meet third party costs*
   We have apportioned revenue streams to cover the following costs during the 26 year projection period:
   - Debt Repayment
   - Interest and Finance Costs
   - Operating Costs

2. *Revenue required tax component*
   Taxes are a major cost component. While we have calculated a corporate tax liability to be paid annually, we have also considered tax losses that may be incurred during the projection period. The revenue tax component essentially provisions for corporate taxes to be paid in a particular period. We have therefore applied a 'Gross-Up' method, where by the taxes are calculated on costs that vary in direct proportion to changes in revenue i.e. third party costs and equity revenue received.

3. *Equity Revenue Factor*
   As per the funding structure adopted for each option (excluding the refinery), we have ensured a 15% equity return to each asset in US$ terms, to be fully recovered after consideration of the cash inflows (equity investment) and cash outflows (debt obligations, capital and operating costs, and taxes). This level of return is typical for Government sponsored projects. For the refinery viability calculations (outside the model), a 10% Weighted Average Cost of Capital (WACC) was used.

### Step 3: Outputs

Drawing from the assumptions and calculations in the Financial Model, we constructed financial statements for the crude pipeline options and the product pipeline options in accordance with International Financial Reporting Standards in the form of an Income Statement, Balance Sheet and Cash Flow Statement for the 26 year projection period.

The macro is designed to assist with the 'revenue required' calculation is dependent on the profit and loss statement in each option.

### Step 4: Viability

For the crude pipeline and product pipeline categories, the output financial statements provide insight into project economics and consequently an analysis of viability.

For the refinery and storage infrastructure sets, the project funding analysis informs further 'off-model' qualitative analysis and commentary on the viability of the projects in these two categories.

**Model Layout and Worksheet Descriptions:**

**Worksheet: Info**

Contains a description of the model contents and worksheets as well as a cell reference key.

**Worksheet: Control**

This worksheet allows selection or input of routings/locations, financing options, debt mix, construction and operation timing assumptions, demand and supply profiles. Taxation assumptions can also be input directly, at the bottom of this sheet. Input cells are shaded to clearly distinguish them from calculation cells which are clear. In this sheet all input cells are in columns E, F, G, H, I, J and K.

Once selections are made, running the macros (for the crude pipeline and product pipeline) updates the outputs in the results sheet. The control sheet area for the Crude Pipeline options is shown below:

*Figure K – 3: Control Sheet (Crude Pipeline area)*

**Crude Pipeline**

**Crude Pipeline 1 - Common Pipeline Phase 1**

| | | |
|---|---|---|
| Routing | Lokichar - Eldoret - Mombasa (Southerly route) | Crude Pipeline Solver |
| Capex Case | Base Case | |

| Capex | Low Case | Base Case | High Case | Construction Period | Construction Start | Delay During Construction |
|---|---|---|---|---|---|---|
| *Lokichar to Lamu (LAPSSET)* | -40% | | 40% | 3 Yr(s) | 2016 | 0 Yr(s) |
| Pipeline | 1,200 | 2,000 | 2,800 | | | |
| 4 booster stations | 360 | 600 | 840 | | | |
| *Lokichar - Eldoret - Mombasa (Southerly route)* | | | | 3 Yr(s) | 2016 | 0 Yr(s) |
| Pipeline | 1,080 | 1,800 | 2,520 | | | |
| 4 booster stations | 360 | 600 | 840 | | | |
| *Lokichar-South of Lamu LAPSSET (Modified)* | | | | 3 Yr(s) | 2016 | 0 Yr(s) |
| Pipeline | 1,200 | 2,000 | 2,800 | | | |
| 4 booster stations | 360 | 600 | 840 | | | |

**Crude Pipeline 2 - Common Pipeline Phase 2**

| | |
|---|---|
| Routing | Lokichar-South of Lamu LAPSSET (Modified) |
| Capex | Base Case |

| Capex | Low Case | Base Case | High Case | Construction Period | Construction Start | Delay During Construction |
|---|---|---|---|---|---|---|
| *Lokichar to Lamu (LAPSSET)* | -40% | | 40% | 3 Yr(s) | 2021 | 0 Yr(s) |
| Pipeline | 840 | 1,400 | 1,960 | | | |
| 2 booster stations | 240 | 400 | 560 | | | |
| *Lokichar - Eldoret - Mombasa (Southerly route)* | | | | 3 Yr(s) | 2021 | 0 Yr(s) |
| Pipeline | 720 | 1,200 | 1,680 | | | |
| 2 booster stations | 240 | 400 | 560 | | | |
| *Lokichar-South of Lamu LAPSSET (Modified)* | | | | 3 Yr(s) | 2021 | 0 Yr(s) |
| Pipeline | 840 | 1,400 | 1,960 | | | |
| 2 booster stations | 240 | 400 | 560 | | | |

**Crude Pipeline 3 (East Rift Connector to Lokichar)**

| | |
|---|---|
| Routing | Turkana - Lokichar |
| Capex | Low Case |

| Capex | Low Case | Base Case | High Case | Construction Period | Construction Start | Delay During Construction |
|---|---|---|---|---|---|---|
| *Turkana - Lokichar* | -40% | | 40% | 2 Yr(s) | 2016 | 0 Yr(s) |
| Pipeline | 120 | 200 | 280 | | | |
| Supporting Infrastructure | 12 | 20 | 28 | | | |
| *Routing B* | | | | 2 Yr(s) | 2016 | 0 Yr(s) |
| Pipeline | - | | - | | | |
| Supporting Infrastructure | - | | - | | | |
| *Routing C* | | | | 2 Yr(s) | 2016 | 0 Yr(s) |
| Pipeline | - | | - | | | |
| Supporting Infrastructure | - | | - | | | |

**Crude Pipeline 4 (Lake Albert connector to Lokichar)**

| | |
|---|---|
| Routing | Hoima - Lokichar |
| Capex | Low Case |

| Capex | Low Case | Base Case | High Case | Construction Period | Construction Start | Delay During Construction |
|---|---|---|---|---|---|---|
| *Hoima - Lokichar* | -40% | | 40% | 3 Yr(s) | 2016 | 0 Yr(s) |
| Pipeline | 900 | 1,500 | 2,100 | | | |
| Supporting Infrastructure | 180 | 300 | 420 | | | |
| *Hoima- Eldoret- Mombasa* | | | | 3 Yr(s) | 2016 | 0 Yr(s) |
| Pipeline | 2,100 | 3,500 | 4,900 | | | |
| Supporting Infrastructure | 360 | 600 | 840 | | | |
| *Routing C* | | | | 3 Yr(s) | 2016 | 0 Yr(s) |
| Pipeline | - | | - | | | |
| Supporting Infrastructure | - | | - | | | |

**Crude Pipeline 5 - Additional Option**

| | |
|---|---|
| Routing | Routing A |
| Capex | High Case |

| Capex | Low Case | Base Case | High Case | Construction Period | Construction Start | Delay During Construction |
|---|---|---|---|---|---|---|
| *Routing A* | -40% | | 40% | 0 Yr(s) | 0 | 0 Yr(s) |
| Pipeline | - | - | - | | | |
| Supporting Infrastructure | - | - | - | | | |
| *Routing B* | | | | 0 Yr(s) | 0 | 0 Yr(s) |
| Pipeline | - | - | - | | | |
| Supporting Infrastructure | - | - | - | | | |
| *Routing C* | | | | 0 Yr(s) | 0 | 0 Yr(s) |
| Pipeline | - | - | - | | | |
| Supporting Infrastructure | - | - | - | | | |

| | | Funding Mix | |
|---|---|---|---|
| | | DFI | ## |
| **Crude Supply** | Base Case | Commercial | ## |
| | | Concessional | ## |
| **Refinancing Facility Amount** | 663 | Additional 1 | ## |
| **Refinancing of Commercial Debt** | On | Additional 2 | ## |

*Check:*

| | |
|---|---|
| Balance Sheet check | TRUE |

*Source: PwC Consortium*

## Worksheet: Results

Based on the selections made in the control sheet, results of the model are displayed here. An excerpt of the crude pipeline results area is illustrated below:

*Figure K – 4: Results sheet (Crude Pipeline area)*

| Crude Pipeline | | | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|
| **Funding Mix** | | | | | | |
| DFI | 75% | | | | | |
| Commercial | 25% | | | | | |
| Concessional | 0% | | | | | |
| Additional 1 | 0% | | | | | |
| Additional 2 | 0% | | | | | |
| **Capex $m** | | | | | | |
| Total | 5,412 | | | | | |
| **Revenue** | | USD m | - | - | 389.46 | 662.15 |
| **Capex** | | USD m | - | 1,386.00 | 2,706.00 | 1,320.00 |
| **Debt Service** | | USD m | - | 56.01 | 165.35 | 376.54 |
| **$/tonne** | | | - | - | - | 47.91 |
| **$/bbl** | | | | | | |

*Source: PwC Consortium*

## Worksheet: Ratios

This sheet displays key financial ratios based on the selections made in the control sheet. These include Debt to Equity, Debt Service Coverage and Profit ratios. An excerpt of the ratio sheet area for the Crude Pipeline options is shown in the figure below:

*Figure K – 5: Ratios sheet (Crude Pipeline area)*

| Crude Pipeline | | | | |
|---|---|---|---|---|
| **Key Ratios** | | | | |
| **Debt Equity Ratio** | | | | |
| Total Debt | - | 1,130 | 2,864 | 3,631 |
| Equity | - | 416 | 1,228 | 1,624 |
| **Debt Equity Ratio** | - | 2.72 | 2.33 | 2.24 |
| **Debt Service Coverage Ratio** | | | | |
| Cash Flow Available for Debt Service | - | (104) | 366 | 657 |
| Debt Service | - | 56 | 165 | 377 |
| **DSCR** | 0.0x | -1.9x | 2.2x | 1.7x |
| **Gross Profit Margin** | | | | |
| Gross Profit | - | - | 389 | 657 |
| **Gross Profit Margin** | 0.0% | 0.0% | 100.0% | 99.2% |
| **Net Profit Margin** | | | | |
| Profit After Tax | - | (160) | (4) | 168 |
| **Net Profit Margin** | 0.0% | 0.0% | -1.1% | 25.3% |

*Source: PwC Consortium*

Assumptions Sheets:

Whereas the control sheet allows selection of routing/location and financing variables for comparison, the assumptions sheets are where changes to the assumptions underlying the above mentioned variables can be made.

**Worksheet: NTBA**

The NTBA sheet contains non-time based assumptions including general timing and units, capital costs, operating assumptions (construction start date and construction period), operating costs, depreciation, working capital, funding, taxation and discount rate (equity rate of return). It also contains geographical uplift and tariff rates for the product pipelines.

Input cells are shaded to clearly distinguish them from calculation cells which are clear. The input cells are primarily in column E.

For funding options, input cells are in columns E, F, G, H, I, and K. Columns H and I provide functionality for additional options (beyond DFI, Commercial and Concessional) to be considered.

**Worksheet: Crude Pipeline TBA**

The Capex Spend profile assumptions for the crude pipeline options are included here as input cells from column H to AG (again, shaded as elsewhere in the model). These inputs drive the capex costing and operating costing assumptions below (both are non-input, derived assumptions driven by the capex spend profile as well as assumptions in the NTBA sheet).

**Worksheet: Products Pipeline TBA**

The Capex Spend profile assumptions for the products pipeline options are included here as shaded input cells from column H to AG. These inputs drive the capex costing and operating costing assumptions below (both are non-input, derived assumptions driven by the capex spend profile as well as assumptions in the TBA sheet).

**Worksheet: Refinery TBA**

The Capex Spend profile assumptions for the refinery options are included here as shaded input cells from column H to AG and these inputs drive the capex costing assumptions below.

**Worksheet: Storage TBA**

The Capex Spend profile assumptions for the storage options are included here as shaded input cells from column H to AG. These inputs drive the capex costing derived assumptions below. This sheet also contains volume assumptions, derived from the inputs in the Volumes sheet.

**Worksheet: Volumes**

This sheet contains the crude pipeline volume (supply) inputs informed by the various supply scenarios (Base Case, Low Case and High Case) as described in Chapter 4 of this report. These can be updated as and when new information becomes available by altering the values in the shaded input cells between column H and column AG.

The product pipeline volume inputs are located further below in this sheet. As with the crude pipeline volume (demand) inputs, the shaded input cells between column H and column AG can be altered to update the model.

Output Financial Statement Sheets

**Worksheet: FS – Crude Pipeline**

These are output financial statements (Profit and Loss, Balance Sheet and Cash Flow) for the consolidated crude pipeline options as selected in the Control sheet.

**Worksheet: FS – Products Pipeline**

These are output financial statements (Profit and Loss, Balance Sheet and Cash Flow) for the consolidated products pipeline options as selected in the Control sheet.

Workings Sheets

These contain the calculations for funding, taxation and revenue requirements based on the assumptions inputted and the variables selected in the control sheet. These calculations feed into the output financial statements for the Crude and Products pipelines, and inform the qualitative analysis on viability of the Refinery, and Storage infrastructure options.

The Crude Pipeline, Products Pipeline, Refinery, and Storage categories each have separate workings sheets.

Fixed Assets Sheets

These sheets include the additions, depreciation charge and net book value calculations based on the inputs in the NTBA and TBA sheets. The Crude Pipeline, Products Pipeline, Refinery, and Storage categories each have separate fixed assets calculation sheets.

# *Gas Financial / Economic Model*

**Overview**

The Gas financial/economic model provides GoK with a tool to estimate **netback** values from market prices for the key monetisation options under consideration. Netbacks are determined at the plant gate (i.e. the inlet for gas supply to the plant), deducting unit costs of production from assumed market prices, and providing an indication of the maximum feedgas price (in US$/MMBtu) that the project can afford in to make an assumed rate of return. Generally:

Netback price = Market price – Cost of Production

The model analyses costs of production based on different financing packages, opex and capex assumptions, and also examines netback prices based on different market prices. Results are presented in Real US$ 2015 values, assuming the investment decision is made at the start of 2015 and accounts for the construction time and hence capex spread for different monetisation options.

This information provides insight into the project economics (including cost of production for different monetisation options) which may assist GoK on policy formation for the monetisation of natural gas discoveries.

**Methodology**

The model analyses five key monetisation options:

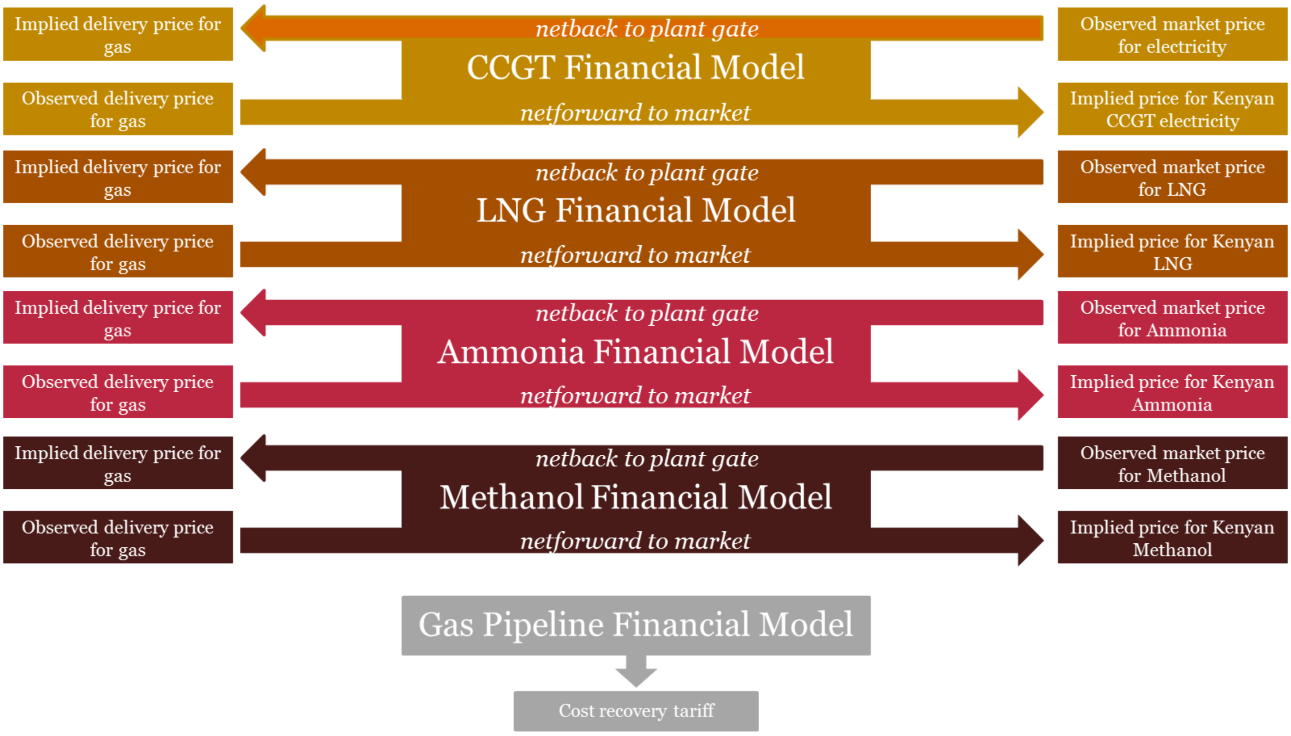
- An 800MW Gas-fired power plant (CCGT),
- A minimum 2 train Liquefied Natural Gas (LNG) plant,
- A 1mtpa Ammonia or Methanol plant,

- Gas transmission pipeline (for three major routes: 1) Lamu-Mombasa (300km, offshore), 2) Mombasa-Nairobi (450km) 3) Lamu-Isiolo/Meru-Nairobi (750km))

The model includes the functionality to **net forward** from assumed feedgas prices in order to determine the impact of different feedgas price assumptions on product market prices. The model also includes functionality for an additional option to be considered, though capex estimates would need to be re-estimated by the user. An indication on unit capital costs is provided in the detailed write up for each monetisation option in the report.

The figure below illustrates the foundation blocks of the model:

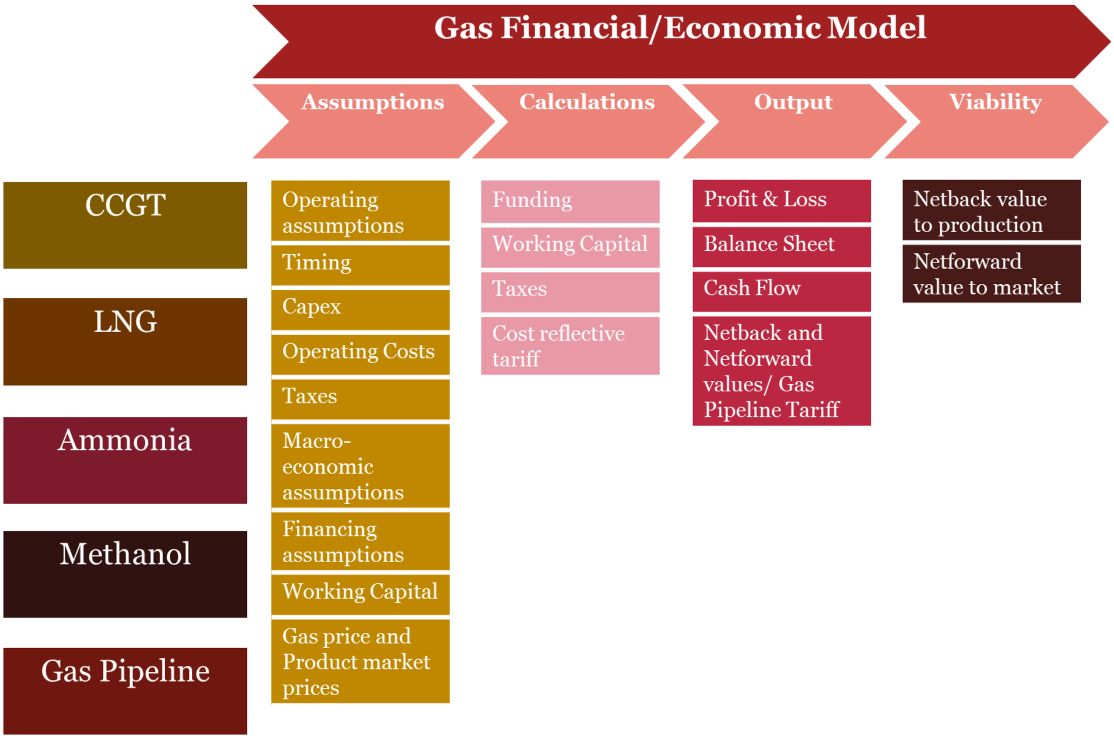
*Figure K - 6: Gas financial/economic model building blocks*




*Source: PwC Consortium*

The diagram shown in the figure below outlines the broad structure of the model and the associated relationship between the input, calculation and evaluation sheets driven by our viability analysis.

*Figure K - 7: Financial model structure*




*Source: PwC Consortium*

**Key Financial Metrics and Assumptions**

## Key Financial Metrics

There are a number of financial metrics the model adopts in order to determine the revenue required for the viability of each option:

**Internal Rate of Return**: Each of the options analysed has been structured to assume an Equity IRR of 15% in US$ terms for each entity (this assumption can be varied).

**Overall cash flow**: We considered the real (projected) cash flows of each option to understand whether there are any periods in which an overdraft occurs, to ensure the funding options have been optimised for each entity.

## Step 1: Assumptions

### Timing

- Model Start Date – 2015
- Projection Period – 26 Years (up to 2040, including construction period)

### Macroeconomic Assumptions

#### *Currency and exchange rates*

All monetary values are stated in US dollar terms unless otherwise stated. Reference to Kenya Shillings (KES) has been made at a translation into US dollars at [US$ 1 = KES 89.16]. However there are no KES inputs. *(http://www.oanda.com/currency/converter/, 1 December 2014).*

## Inflation

The model is represented in real terms over the Projection Period.

### Accounting Assumptions

The model has been constructed to give financial reporting consistent with International Financial Reporting Standards as displayed in terms of income statement, cash flow statement and balance sheet.

### Volume, Capital and Operating Costs

The model is based on the volumes, capital and operating costs as defined early in this Report and determined as a result of the technical review, i.e. the supply estimates for gas resources, and demand projections (particularly for electricity).

### Financing Assumptions

For each asset we have assumed a set of financing assumptions, based on the prevailing Development Finance Institution (DFI), Commercial Bank and Concessional Financing funding terms that have been seen on infrastructure type finance raising projects within the region. The model allows for scenarios based on a combination of debt sources. Provision for comparison of two additional financing options has been made in the model.

We present in the table below the financing assumptions for the CCGT Power Company. These are illustrative of the assumptions used for the other infrastructure categories (LNG, Ammonia, Methanol and Gas Pipeline).

*Table K - 5: Financing assumptions*

| CCGT Power | | | Development Finance Institutions | Commercial | Concessional | Refinancing of Commercial Debt |
|---|---|---|---|---|---|---|
| **Debt** | | | | | | |
| Gearing (Debt: Equity) | 70% | % | | | | |
| Senior Loan | OK | % | 75% | 25% | 0% | ON |
| Senior Loan (Proportion total funding) | | % | 52.5% | 17.5% | 0.0% | |
| Tenor | | Yrs | 15 Yr(s) | 7 Yr(s) | 25 Yr(s) | 5 Yr(s) |
| Base Rate (6 month Libor) | | % | 0.40% | 0.40% | 0.40% | 0.32% |
| Front-end Fee | | | 1.25% | 1.25% | 0.00% | 0.00% |
| Arrangement fee | | % | 0.25% | 1.50% | 0.50% | 1.50% |
| Commitment fee | | % | 1.00% | 2.00% | 0.00% | 2.00% |
| Interest Margin | | % | 5.00% | 6.50% | 1.00% | 7.50% |
| All in Interest Rate | | % | 5.40% | 6.90% | 1.40% | 7.82% |
| Term | | | | | | |
| From | | Year | 2015 | 2015 | 2015 | 2022 |
| Tenor | | Yrs | 15 Yr(s) | 7 Yr(s) | 25 Yr(s) | 5 Yr(s) |
| Grace Period End | | Year | 2018 | 2017 | 2026 | 2023 |
| Grace Period Equal to: | | Yrs | 2 Yr(s) | 1 Yr(s) | 10 Yr(s) | 0 Yr(s) |
| End | | Year | 2030 | 2022 | 2040 | 2027 |
| **Equity** | | | | | | |
| Proportion of Equity | | % | 30% | | | |
| Drawing Method | | | Prorate | | | |
| Equity Injection | | | | | | |
| Share Capital | | % | 100% | | | |

*Source: PwC Consortium*

## Other Assumptions

1. Taxes
   - Corporate tax = 30%
   - Tax losses = Carry forward for 4 years
2. Depreciation

An implied depreciation rate for each project is calculated based on the Estimated Useful Life of each infrastructure category.

*Table K - 6: Depreciation rates*

| Depreciation | Estimated Useful Life | Implied Depreciation Rate |
|---|---|---|
| | | |
| **CCGT** | | |
| **Shipping** | 24 Yr(s) | 4.17% |
| **Port handling and storage** | 24 Yr(s) | 4.17% |
| **Road transport** | 24 Yr(s) | 4.17% |
| **Plant** | 24 Yr(s) | 4.17% |
| **Gas pipeline** | 24 Yr(s) | 4.17% |
| **Processing** | 24 Yr(s) | 4.17% |
| | | |
| **LNG** | | |
| **Shipping** | 21 Yr(s) | 4.76% |
| **Port handling and storage** | 21 Yr(s) | 4.76% |
| **Road transport** | 21 Yr(s) | 4.76% |
| **Plant** | 21 Yr(s) | 4.76% |
| **Gas pipeline** | 21 Yr(s) | 4.76% |
| **Processing** | 21 Yr(s) | 4.76% |
| | | |
| | | |
| **NH3** | | |
| **Shipping** | 23 Yr(s) | 4.35% |
| **Port handling and storage** | 23 Yr(s) | 4.35% |
| **Road transport** | 23 Yr(s) | 4.35% |
| **Plant** | 23 Yr(s) | 4.35% |
| **Gas pipeline** | 23 Yr(s) | 4.35% |
| **Processing** | 23 Yr(s) | 4.35% |
| | | |
| **Methanol** | | |
| **Shipping** | 23 Yr(s) | 4.35% |
| **Port handling and storage** | 23 Yr(s) | 4.35% |
| **Road transport** | 23 Yr(s) | 4.35% |
| **Plant** | 23 Yr(s) | 4.35% |
| **Gas pipeline** | 23 Yr(s) | 4.35% |
| **Processing** | 23 Yr(s) | 4.35% |
| | | |
| **New option** | | |
| **Shipping** | 23 Yr(s) | 4.35% |
| **Port handling and storage** | 23 Yr(s) | 4.35% |
| **Road transport** | 23 Yr(s) | 4.35% |
| **Plant** | 23 Yr(s) | 4.35% |
| **Gas pipeline** | 23 Yr(s) | 4.35% |
| **Processing** | 23 Yr(s) | 4.35% |
| | | |
| **Gas pipeline** | 23 Yr(s) | 4.35% |

*Source: PwC Consortium*

3. Product Market Prices

For the netback price calculations, various Base Case, High Case and Low Case prices can be assumed for each of the options products. For example for CCGT power, one could assume an electricity sales prices of US$100/MWh, US$130/MWh and US$70/MWh for Base, High and Low Cases respectively. Feedgas price are set as US$5/MMBtu for the net forward (product price) calculation, but again, this can be altered.

### Step 2: Calculations

**Revenue**

The Model calculated revenue based on assumed market prices. Production costs (including a 15% return to equity in US$ terms) are subtracted from revenue to arrive at a netback to plant gate value.

### Step 3: Outputs

Drawing from the assumptions and calculations in the Financial Model, we constructed financial statements for all the options in accordance with International Financial Reporting Standards in the form of a Profit and Loss Statement, Balance Sheet and Cash Flow Statement for the 26 year projection period.

### Step 4: Viability (Revenue Required, and Net forward and Netback Values)

The output financial statements provide insight into project economics and consequently an analysis of project viability. Further the net forward to market and netback to plant gate calculations inform analysis into the **viability of the various monetization options**. The net forward values generated by the model, provide insight into the project's competitiveness under different feedgas cost assumptions. Whereas the netback values provides insight on the impact of market prices on the project’s affordability of gas supply.

**Model Layout and Worksheet Descriptions:**

**Worksheet: Info**

Contains a description of the model contents and worksheets as well as a cell reference key.

**Worksheet: Control**

This worksheet allows direct input of capex, sales price and construction related assumptions as well as selection of financing options and debt mix. Taxation assumptions can also be input directly, at the bottom of this sheet. Input cells are shaded to clearly distinguish them from calculation cells which are clear. In this sheet all input cells are in columns E, F and G.

Once selections are made, running the macros updates the outputs (tariff, netback and net forward values). The control sheet area for the CCGT option is shown in the figure below:

## *Figure K - 8: Control sheet (CCGT area)*

**CCGT**

| | | | | | |
|---|---|---|---|---|---|
| Tariff Calculation (Netback = 1, Netforward = 2) | | | 2 | CCGT Solver | |
| **Capex Case** | | | Base Case | | |
| **Capex** | | | **Low Case** | **Base Case** | **High Case** |
| Shipping | *QED Gas* | USD millions | - | - | - |
| Port handling and storage | *QED Gas* | USD millions | - | - | - |
| Road transport | *QED Gas* | USD millions | - | - | - |
| Plant | *QED Gas* | USD millions | 600 | 875 | 1,040 |
| Gas pipeline | *QED Gas* | USD millions | - | - | - |
| Processing | *QED Gas* | USD millions | - | - | - |
| **Price** | | | Base Case | | |
| | | | **Low Case** | **Base Case** | **High Case** |
| **Sales Price** | *QED Gas* | $/MWh | 70 | 100 | 130 |
| | | | | **Funding Mix** | |
| **Refinancing Facility Amount** | | | 107 | **DFI** | 75% |
| **Refinancing of Commercial Debt** | | | On | **Commercial** | 25% |
| | | | | **Concessional** | 0% |
| Construction period | *QED Gas* | | 2 Yr(s) | **Additional 1** | 0% |
| Construction start year | | | 2015 | **Additional 2** | 0% |
| Delay during construction | | | 0 Yr(s) | | |

*Check:*

| Tariff | Feedgas Cost (Netback from Sales Price) | Product Price (Netforward from Feedgas Price) |
|---|---|---|
| 37.9 | 10.0 | 68.9 |
| 100.0 | 5.0 | |
| 100.0 | | 68.9 |
| - | | - |

| | |
|---|---|
| NPV check | TRUE |
| Balance Sheet check | TRUE |

*Source: PwC Consortium*

### Worksheet: Results

Based on the selections made in the control sheet, results of the model are displayed here. An excerpt of the results sheet area for the CCGT option is shown in the figure below:

*Figure K - 9: Results sheet (CCGT area)*

| CCGT - 800MW | | | | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|
| **Funding Mix** | | | | | | |
| DFI | 75% | | | | | |
| Commercial | 25% | | | | | |
| Concessional | 0% | | | | | |
| Additional 1 | 0% | | | | | |
| Additional 2 | 0% | | | | | |
| **Capex Option** | Base Case | | | | | |
| Sales Price $/MWh | 100 | | | | | |
| Capex $m | 875 | | | | | |
| **Tariff** | 37.91 | | | | | |
| **Feedgas Cost (Netback from Sales Price)** | 10.01 | | | | | |
| **Product Price (Netforward from Feedgas Price)** | 68.93 | | | | | |
| **Revenue** | | USD m | | - | - | 277.91 |
| **Capex** | | USD m | | 437.50 | 437.50 | - |
| **Debt Service** | | USD m | | 17.68 | 35.36 | 60.88 |

*Source: PwC Consortium*

### Worksheet: Ratios

This sheet displays key financial ratios based on the selections made in the control sheet. These include Debt to Equity, Debt Service Coverage and Profit ratios. An excerpt of the ratio sheet area for the CCGT option is shown in the figure below:

*Figure K - 10: Ratios sheet (CCGT area)*

| Year | | 2015 | 2016 | 2017 |
|---|---|---|---|---|
| Operating Period | Units | 1 | 2 | 3 |
| **CCGT** | | | | |
| **Key Ratios** | | | | |
| **Debt Equity Ratio** | | | | |
| Total Debt | | 339 | 680 | 608 |
| Equity | | 131 | 263 | 263 |
| **Debt Equity Ratio** | | 2.58 | 2.59 | 2.31 |
| **Debt Service Coverage Ratio** | | | | |
| Cash Flow Available for Debt Service | | (15) | - | 118 |
| Debt Service | | 18 | 35 | 61 |
| **DSCR** | | -0.8x | 0.0x | 1.9x |
| **Gross Profit Margin** | | | | |
| Gross Profit | | - | - | 118 |
| **Gross Profit Margin** | | 0.0% | 0.0% | 42.4% |
| **Net Profit Margin** | | | | |
| Profit After Tax | | (33) | (72) | 46 |
| **Net Profit Margin** | | 0.0% | 0.0% | 16.6% |

*Source: PwC Consortium*

Assumptions Sheets:

Whereas the control sheet allows selection of financing variables for comparison, the assumptions sheets are where most of the changes to the assumptions underlying the various variables can be made.

**Worksheet: NTBA**

The NTBA sheet contains non-time based assumptions including general timing and units, operating costs, operating assumptions, depreciation, working capital, funding, taxation and discount rate (equity rate of return). Again, input cells are shaded to clearly distinguish them from calculation cells which are clear. The input cells are primarily in columns E, except for funding and taxation assumptions, where input cells are in columns E F, G, H, I, J and K. Columns H and I provide functionality for additional options (beyond DFI, Commercial and Concessional) to be considered.

**Worksheet: Timing and Setup**

This sheet contains the time based assumptions. Inflation assumptions can be input in the shaded cells in rows 11 and 12 (columns F to J, and F to K, respectively). The Capex Spend profile assumptions for the crude pipeline options are included here as input cells from column F to AE (again, these are shaded to differentiate them from calculation cells). These inputs drive the capex costing and operating costing assumptions below (both are non-input, derived assumptions driven by the capex spend profile as well as assumptions in the NTBA sheet). The production assumptions, driven by inputs in the NTBA sheet are also included here.

Output Financial Statement Sheets

**Worksheet: FS – CCGT**

These are output financial statements (Profit and Loss, Balance Sheet and Cash Flow) for the CCGT option as per the assumptions selected/input.

**Worksheet: FS – LNG**

These are output financial statements (Profit and Loss, Balance Sheet and Cash Flow) for the CCGT option as per the assumptions selected/input.

**Worksheet: FS – NH3**

These are output financial statements (Profit and Loss, Balance Sheet and Cash Flow) for the Ammonia (NH3) option as per the assumptions selected/input.

**Worksheet: FS – Methanol**

These are output financial statements (Profit and Loss, Balance Sheet and Cash Flow) for the Methanol option as per the assumptions selected/input.

**Worksheet: FS – Additional Option**

These are output financial statements (Profit and Loss, Balance Sheet and Cash Flow) for the Additional option as per the assumptions selected/input.

**Worksheet: FS – Gas Pipeline**

These are output financial statements (Profit and Loss, Balance Sheet and Cash Flow) for the Gas Pipeline option as per the assumptions selected/input.

Workings Sheets

These contain the calculations for funding, taxation, tariff, net forward and netback values based on the assumptions input and the variables selected in the control and assumptions sheets. These calculations feed into the output financial statements for each option.

The CCGT, LNG, Ammonia, Methanol, Gas Pipeline as well as the Additional option categories each have separate workings sheets.

Fixed Assets Sheets

These sheets include the additions, depreciation charge and net book value calculations based on the inputs in the Control, NTBA and Timing and Setup sheets. The CCGT, LNG, Ammonia, Methanol, Gas Pipeline as well as the Additional option categories each have separate fixed asset calculation sheets.

# Appendix L. - Detailed Benchmarking Section

## Introduction

The PwC consortium benchmarked Kenya with a group of countries to draw learning points from the trajectory followed by these countries in the development of their oil and gas sectors.

In order to come up with a set of learning points and best practice we selected countries based on the following criteria:

- The comparability of the country to Kenya in terms of the trajectory of its economic development and its political history.
- Extent to which the country has been able to attract investment into its oil and gas sector and develop markets for its oil and gas resources.
- Best practices that Kenya can adopt from the trajectory followed by the country or lessons that Kenya can learn.

Following consultations and discussions with the Kenya Petroleum Master Planning Steering Committee, eight countries were shortlisted. We categorised the countries within upstream, midstream and downstream and identified specific areas within their oil and gas sectors for review. For the exercise, the PwC Consortium researched literature, applied their experience from working in these countries and summarised their observations and learning points for Kenya.

*Table L - 1: Benchmark Countries*

| Area | Country |
|---|---|
| **Upstream** | Canada<br>Trinidad and Tobago<br>Malaysia<br>Israel<br>Nigeria<br>Ghana |
| **Midstream and Downstream** | Turkey<br>Nigeria<br>India<br>Malaysia<br>Trinidad and Tobago<br>Canada |

We also highlighted experience from other countries outside of this list (such as Australia) in areas where comparison was relevant.

# Benchmarking – Upstream

## Malaysia

Malaysia is the second largest oil and natural gas producer in Southeast Asia, the second largest exporter of liquefied natural gas globally, and is strategically located amid important routes for seaborne energy trade.[26]

Oil in Malaysia was discovered in 1910 in Sarawak following exploration activities by Royal Dutch Shell Group.[27] This discovery provided a platform for various investments into the sector with the first refinery being built four years later in 1914. During this period exploration and production acreage was awarded through concessions, with Shell and Esso being key players carrying out exploration activities in Malaysia.

In 1974, Malaysia created its own national oil company, Petroliam Nasional Berhad (PETRONAS) which was granted rights to the country's hydrocarbons as stipulated under the Petroleum Development Act 1974 ("Petroleum Act").[28] The Production Sharing Contract (PSC) regime was introduced thereafter whereby oil companies with intent to explore and produce oil and gas in Malaysia were engaged by PETRONAS under a PSC. Since incorporation PETRONAS has played a significant role in the oil and gas sector taking part in the upstream, midstream and downstream activities in the sector.

Since the inception of PETRONAS, Malaysia has grown to be a major oil and gas producer moving from a net importer to a net exporter of crude oil.

Malaysia's crude oil production has increased substantially from the level of about 18,000 barrels per day (b/d) in 1970 to 445,000 b/d in 1985 and 722 b/d in 2000. The country currently has proven oil reserves of 3.7 billion barrels of oil equivalent with an average production of 657,000 barrels per day (b/d). Proven natural gas reserves in Malaysia stand at 1.1 Trillion cubic metres (Tcm) with a production rate of about 69 Billion cubic meters /year (Bcm).[29]

### Licensing regime and commercial structure

Prior to 1976, Malaysia awarded oil and gas acreage under a concession regime which was governed under the Petroleum Mining Act 1966. Under the concession all explorations costs were borne by the operators and in exchange the operators had liberty over all operations including procurement contracting and technological decisions.

In 1974 several economic and political changes were occurring in Malaysia. World oil prices were on the increase incentivizing Malaysia to increase their share of oil profits, in common with many other oil producing nations at that time. At the same time several countries were moving from the concession system to the PSC system including neighbouring Indonesia. In addition, Malaysia was experiencing a growing sense of nationalism. These events led to the formation of the national oil company Petronas and thereafter the introduction of licensing of acreage under the PSC system.

In the current regime, PETRONAS holds exclusive ownership rights to all oil and gas exploration projects and administers this through an exploration licence. Companies wishing to conduct exploration and production activities enter into a PSC arrangement with Petronas for a share of profits after payment of taxes and royalties. The first PSC was signed in 1976 with Shell and to date Petronas has entered into over 70 PSC agreements with various contractors.

26 U S Energy Information Administration, 2013
[27] Malaysia Petroleum Resources Corporation,2013, http://www.mprc.gov.my/industry/history-of-oil-gas-in-malaysia
[28] Bank Pembagunan- Annual Report , (2011), http://www.bpmb.com.my/GUI/pdf/annual_report/2011/BPM_AR2011.pdf
[29]BP, *Statistical Review of World Energy* , 2014

Under this legislation, Petronas is entitled to hold a minimum of 15% equity in the relevant fields and in practice this has usually varied between 15% and 25%.[30] Under the PSC, the oil companies bear all the risk of exploration, development and production activities in exchange for a share of the total production.

In 1997, a new PSC regime was introduced based on revenue over cost (R/C PSC). This was to encourage further investment into the sector which had tailed off. Under the R/C PSC, contractors were able to accelerate their cost recovery if they achieved certain cost targets.

Also under the R/C PSC, oil companies are allowed a higher share of the production when profitability is low while Petronas share of the production is increased when oil Companies' profitability is improved. Production revenues are charged a 10% royalty while cost recovery varies between 30% - 70%. The applicable income tax rate is 38% although in 2010, the applicable tax rate for smaller fields was dropped to 25% to attract investment. Export duty on oil and condensate is 10%.[31]

Besides the R/C PSC, Malaysia also adopts other PSC regimes for deep water and high pressure exploration activities where the technological risks are higher.

## Fiscal regime in light of dropping reserves[32]

In recent years, Malaysia has experienced dwindling reserves due to maturing hydrocarbon basins. In 2013, Petronas' production reduced to 480,000 b/d from a peak output of 650,000 b/d achieved about two decades earlier. It has become clear to market players that decreasing supply against an increasing demand from population growth is a challenge that policy makers have to address.

In light of decreasing reserves Petronas has sought to boost development of marginal fields to increase domestic oil production. Marginal fields considered to have less than 30 million barrels of recoverable oil or oil equivalent require more cost to develop and bear greater risk to developers. By balancing this risk with developers, the country adopted Risk Service Contracts (RSC) in 2011 to encourage investments into these fields. Under the RSC, Petronas assumes the role of project owner while oil companies are service providers.

Upfront fees of development incurred by the oil companies are recovered upon production, together with a fixed fee for service rendered based on performance. Malaysia has since signed Risk Service Contracts with various oil companies for the development of marginal fields including the Berantai field, about 150km offshore, which has since delivered production .

## Local content

Unlike the concession regime, under the existing PSC model contractors are required to maximize local participation by the use of local equipment, facilities, goods, materials, supplies and services in petroleum operations. Priority is given to Malaysian registered companies in their procurement of supplies and services in any tender exercise such that a contract will be awarded to a foreign registered company only if there are no Malaysian registered companies available to perform the required services. In addition, under the cabotage policy introduced in 1980 domestic shipping has been reserved to Malaysian registered vessels.

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[30] Bank Pembagunan- Annual Report , (2011), http://www.bpmb.com.my/GUI/pdf/annual_report/2011/BPM_AR2011.pdf
[31] R.V.Putrohari et al, *"PSC term and condition and its implementation is South East Asia Region"*, Indonesia 31 Annual and Convention and Exhibition ,2007

[32]Petronas, *Our Energy Future* ,(2013), www.petronas.com.my/media-relations/.../Our%20Energy%20Future.pdf

Furthermore, contractors are required to minimize the employment of foreign workers and are required to attain the approval of Petronas before the recruitment of foreign nationals. Contractors are also required to train local Malays and provide capacity building programmes where local Malays can in time replace foreign workers. In addition, upon the request of Petronas, contractors are also required to offer on-the-job training to Petronas personnel.

To further enhance participation of local companies and build their capacity for exploration of marginal fields, international companies that are licensed under Risk Service Contracts are required to partner with local companies listed in the Bursa Malaysia stock exchange.

The Government of Malaysia continues to adopt various strategies to build local capabilities. Under Malaysia's Economic Transformation Programme (ETP) the Government aims to transform Malaysia into a hub for Oil Field Services and Equipment (OFSE) and is adopting various strategies including the following:[33]

- Introducing tax and other incentives to attract multinationals to bring their global oil field service and equipment operations to Malaysia.
- Encouraging gains in efficiencies within domestic fabricators through consolidation of companies. This initiative has since been successful with the establishment of three Engineering, Procurement, Construction and Commissioning (EPCC) companies from eight small to medium sized fabricators. Going forward the Government under the ETP is encouraging local firms to export their products and services to international markets by facilitating cross border investments by providing access through Government to Government linkages.
- Offering incentives for multinational companies to form joint ventures with local companies in OFSE activities.

The Government has delegated responsibility to Petronas and two other agencies established under the Prime Minister, Malaysian Investment Development Authority and Malaysia Petroleum Resources Corporation to ensure that local content initiatives are designed and implemented.

## Major players

### National Oil Company participation[34]

In Malaysia the national oil company Petronas is involved in all aspects of the oil and gas value chain. Its business activities include:

The exploration, development, and production of crude oil and natural gas in Malaysia and overseas;
The liquefaction, sale, and transportation of liquefied natural gas (LNG);
The processing and transmission of natural gas and the sale of natural gas products;
The refining and marketing of petroleum products;
The manufacture and sale of petrochemical products;
The trading of crude oil, petroleum products, and petrochemical products; and
Shipping and logistics relating to LNG, crude oil, and petroleum products in the upstream activities.

In the upstream sector Petronas is a key player through its subsidiary Petronas Carigali Sdn Bhd which works alongside a number of petroleum multinational corporations through PSCs to explore, develop and produce oil and gas in Malaysia. Petronas is also involved in managing PSCs in the country and oversees exploration and production activities in Malaysia.

Petronas takes the largest share of exploration and production activities. Other than Petronas, other key players in exploration and production in 2011 were Shell and ExxonMobil. Petronas , Shell and ExxonMobil in aggregate undertook over 80% of total production accounting for 43%, 22% and 16% of total production respectively.

[33] Economic Transformation Programme Annual Report,(2013), etp.pemandu.gov.my/annualreport/
[34] www.petronas.com,2014

Regulatory structure and the role of PETRONAS

In Malaysia, energy policy for the upstream sector is determined by the Economic Planning Unit (EPU) and the Implementation and Coordination Unit (ICU), both of which report directly to the Prime Minister. The EPU is the principal Government agency in Malaysia that was set up in 1961 to focus on development planning. Other than the provisions of the Petroleum Act, activities in the upstream sector are also governed by the Petroleum Income Tax Act 1967 and Petroleum Income Tax Amendment Act 1976.

The Petroleum Management Unit (PMU) of Petronas acts as the resource owner and manager of Malaysia's oil and gas assets. The PMU is charged with awarding exploration and production blocks and PSCs and regulates and monitors upstream activities including approving work programmes and budgets and approving sub-contractors of supplies and services. The Supply Chain Management Division (SCMD) of Petronas is charged with formulating procurement policies, licensing and registration of operating companies involved in upstream activities. The SCMD acts as the tender secretariat managing tendering activities of upstream supplies and services.

The institutions responsible for policy formulation, implementation and regulation of the upstream sector fall under the Prime Minister. Although this has the advantage that critical decisions can be reached quicker it also bears the risk of compromising the professionalism and independence of such decisions.

PETRONAS' role in the transfer of knowledge

Through strong industry participation by PETRONAS and its partnership with international contractors, there has been a transfer of knowledge and skills which has built local capability and capacity. Oil production in Malaysia increased considerably following the formation of PETRONAS moving from 91,000 b/d in 1973 to 446,000 b/d by 1984 and peaking at 776,000 b/d by 2004.[35] Although the company's focus was concentrated in the upstream sector in the first half of its existence, PETRONAS has also increased its activities in the midstream and downstream sectors as well.

By building its capacity PETRONAS has transformed to become a key oil and gas player rendering services in Malaysia and in over 30 countries including African nations such as Sudan, Algeria and South Africa. Through its success the company has earned the Government significant receipts from taxation. It has also established educational and training institutions and an e-learning platform through which Malaysian students can receive the required training. One institution established by PETRONAS is the Universiti Teknologi PETRONAS (UTP), a science and technology institutions of higher learning hosting about 7,200 undergraduate and graduate students and offering various courses including geosciences and petroleum engineering.

1. The early establishment of an institution responsible for Government participation in the upstream sector, with direct reporting to the prime minister, created the proper environment in which PETRONAS has grown to be a major player in all aspects of the Malaysia's oil and gas sector.

[35] BP, *Statistical Review of World Energy* , 2014

# Nigeria

Nigeria is the largest oil producer in Africa. Nigeria holds the largest natural gas reserves on the continent, and was the world's fourth leading exporter of liquefied natural gas (LNG) in 2012. Nigeria became a member of the Organization of the Petroleum Exporting Countries (OPEC) in 1971, more than a decade after oil production began in the oil-rich Bayelsa State in the 1950s. Although Nigeria is the leading oil producer in Africa, production suffers from supply disruptions, which have resulted in unplanned outages as high as 500,000 barrels per day (b/d).

Some of the reasons affecting supply include conflict in the Niger Delta region, where the oil and natural gas industries are primarily located. Local groups seeking greater share of the wealth often attack oil infrastructure, forcing companies to declare force majeure (a legal clause that allows a party to not satisfy contractual agreements because of circumstances that are beyond their control and that prevent them from fulfilling contractual obligations) on oil and LNG shipments. At the same time, oil theft through attacks on oil product pipelines causes damage that is often severe, causing loss of production, pollution, and forcing companies to shut in production.

Ageing infrastructure and poor maintenance have also resulted in oil spills. Also, natural gas flaring, the burning of associated natural gas that is produced with oil, has contributed to environmental pollution. Protests from local groups over environmental damages from oil spills and gas flaring have exacerbated tensions between some local communities and international oil companies (IOCs). The industry has been blamed for pollution that has damaged the air, soil, and water, leading to losses in arable land and decreases in fish stocks.

Nigeria's oil and natural gas resources are the mainstay of the country's economy. The International Monetary Fund estimates that oil and natural gas export revenue accounted for 96% of total export revenue in 2012. For 2013, Nigeria's budget is framed on a reference oil price of US$79 per barrel, providing a wide safety margin in case of price volatility. Savings generated when oil revenues exceed budgeted revenues are placed into sovereign wealth funds, which can then be drawn down in years when oil revenues are below budget.

## Exploration history

Exploration for oil and gas in Nigeria began in 1908. Oil was discovered in Nigeria in 1956 at Oloibiri in the Niger Delta after half a century of exploration. The discovery was made by Shell D'Arcy Petroleum, at the time the sole concessionaire. Following the discovery of crude oil by Shell D'Arcy Petroleum, pioneer production began in 1958 from the company's oil field in Oloibiri in the Eastern Niger Delta with a capacity of 5,100 b/d. Nigeria's first refinery began operations in 1965, with a capacity of 38,000 b/d ; enough to meet domestic requirements at the time. The demand and production of oil in Nigeria have both since increased tremendously; such that Nigeria's current daily production is estimated at 2.5m barrels per day, with a domestic consumption level of 279,000 b/d. At the end of 2013, Nigeria's proven oil reserves were estimated to be 37.1bn barrels, which amounts to 2.68%of the world's reserves.[36]

The crude oil produced in Nigeria is classified as 'sweet', as it is largely sulphur-free. 80%of production wells are located in the Niger delta region in the southern part of the country, with notable projects including the Afam Integrated Oil and Gas Project operated by Shell and the Bonga Deep Water Project, Nigeria's first deep-water oil discovery.

## Licencing Regime[37]

The Petroleum Act is the main statute that deals with petroleum resources and how they may be developed. The Act provides for development of petroleum resources through phases of exploration, prospecting and production and grants to companies registered in Nigeria, separate rights for each phase through a licence/lease regime.

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[36] BP, *Statistical Review of World Energy* , 2014,http://www.bp.com/content/dam/bp/pdf/Energy-economics/statistical-review-2014/BP-statistical-review-of-world-energy-2014-full-report.pdf
[37] Petroleum Act(1969) S. 2

Subject to the Petroleum Act, the Minister may grant:

(a) A licence, known as an **oil exploration licence**, to explore for petroleum. An oil exploration licence shall apply to the area specified therein which may be any area on which a premium has not been placed by the Minister, and shall authorise the licensee to undertake exploration for petroleum in the area of the licence, excluding land in respect of which the grant of an oil prospecting licence or oil mining lease has been approved by the Minister and land in respect of which an oil prospecting licence or oil mining lease is in force. An oil exploration licence shall terminate on 31 December following the date on which it was granted, but the licensee shall have an option to renew the licence for one further year if the Minister is satisfied.

(b) A licence, known as an **oil prospecting licence**, to prospect for petroleum. The holder of an oil prospecting licence shall have the exclusive right to explore and prospect for petroleum within the area of his licence. The duration of an oil prospecting licence shall be determined by the Minister, but shall not exceed five years (including any periods of renewal). The holder of an oil prospecting licence may carry away and dispose off petroleum won during prospecting operations, subject to the fulfilment of obligations imposed upon him by or under the Act.

(c) A lease, known as an **oil mining lease**, to search for, win, work, carry away and dispose off petroleum. An oil mining lease may be granted only to the holder of an oil prospecting licence who has:

- Satisfied all the conditions imposed by the licence or otherwise imposed on him by the Act; and,
- Discovered oil in commercial quantities.

Oil shall be deemed to have been discovered in commercial quantities by the holder of an oil prospecting licence if the Minister, upon evidence adduced by the licensee, is satisfied that the licensee is capable of producing at least 10,000 bbl./d of crude oil from the licensed area. The term of an oil mining lease shall not exceed twenty years, but may be renewed in accordance with the Act.

### Local manpower requirements[38]

The holder of an oil mining lease shall ensure that:

(a) Within ten years from the grant of his lease -

> (i) The number of citizens of Nigeria employed by him in connection with the lease in managerial, professional and supervisory grades (or any corresponding grades designated by him in a manner approved by the Minister) shall reach at least 75% of the total number of persons employed by him in those grades; and,
>
> (ii) The number of citizens of Nigeria in any one such grade shall be not less than 60% of the total.

(b) All skilled, semi-skilled and unskilled workers are citizens of Nigeria.

A licence or lease under this section may be granted only to a company incorporated in Nigeria under the Companies and Allied Matters Act or any corresponding law.

### Competitive bidding39

Prior to 2005 all licences were issued discretionarily by the President. However the Petroleum Act 2004 allowed for a competitive bidding process. The bids were to be opened publicly. This has since been changed by the Petroleum Industry Bill (PIB) that advocated for a closed opening of bids although this Bill has not yet been enacted.

Various arrangements have been used in the Nigerian upstream sector, as set out below.

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[38] Nigeria Oil and Gas Industry Local Content Development Act(2010)
[39] The Petroleum Industry Bill(2012)

- Concession agreement – this was the earliest form of petroleum arrangement in Nigeria. An international oil company (IOC) is granted an Oil Prospecting License (OPL) and on discovery of petroleum in commercial quantities, the company is granted an Oil Mining License (OML). The IOC conducts petroleum operations on its own (subject to regulations by the appropriate authorities), and pays royalties and petroleum profit tax (PPT) to the Government.

- Joint ventures (JVs) – these are arrangements between the state-owned Nigeria National Petroleum Corporation (NNPC) on behalf of the Government and a counterpart IOC whereby the parties hold the OPL or OML jointly and funding for the exploration, development and production of petroleum, and the hydrocarbons produced are shared in proportion to the participating interest held by each party. This arrangement is typically governed by a joint operating agreement (JOA) between NNPC and its IOC joint venture partner that provides for the conduct of petroleum operations. The IOC is typically the operator, with a management committee established to supervise operations. The participatory interest of NNPC is 60 per cent in all JVs, except those operated by Shell (SPDC) where its 55%.

- Production sharing contracts (PSCs) – more recently, to reduce the Government's funding obligations, the Government adopted the PSC as the preferred petroleum arrangement with IOCs for onshore and offshore operations. Under the PSC arrangement, the OPL and the OML is held by NNPC, which engages the IOC or indigenous private investor as a contractor to conduct petroleum operations on its behalf and NNPC. The contractor is responsible for financing all costs of the various stages of petroleum operations i.e. exploration, development and production. When the exploration is successful, the contractor will be entitled to recover its costs, together with a reasonable level of profit when commercial production begins. If the operation is not successful, the contractor will bear all losses.

- Risk service contracts (RSCs) – Under the RSC arrangement, the OPL is held by NNPC, while the service company funds petroleum operations. Each service contract relates to a single concession. The primary term is for two or three years, renewable at NNPC's option for a further two. As the contractor only gets reimbursed from funds derived from the sale of the concession's available oil, when oil is not discovered in commercial quantities then the contractor does not recover its costs. When oil is found, the contractor is paid its costs back in instalments, either in cash or crude oil allocation. The contractor is remunerated by payment of a fixed amount, does not have a participation share and does not acquire title to any crude produced. As such, the contractor is liable to pay Companies Income Tax (CIT, at 30%) and not PPT. As an incentive for the risk taken, the contractor has the first option to purchase certain fixed quantities of crude oil produced from the service contract area at market prices.

### Commercial Structure[40]

Under the current regime, companies and entities engaged in upstream petroleum operations are subject to PPT pursuant to the Petroleum Profits Tax Act (PPTA) while other companies (including those engaged in downstream petroleum operations) are subject to CIT pursuant to the Companies Income Tax Act (CITA). The current rate of PPT is 50% for operations in the deep offshore and inland basin and 85% for operations onshore and in shallow waters.

The Petroleum Industry Bill (PIB) 2012 proposed to replace the existing PPT with a Nigerian Hydrocarbon Tax (NHT) at the rate of 50% for petroleum operations onshore and in shallow water fields and 25% for petroleum operations in deepwater, bituminous and frontier acreages. In addition to NHT, the Bill also proposes CIT at the rate of 30% on upstream petroleum operations (which under the existing regime are not subject to CIT). To achieve the new fiscal regime, the PIB proposed a repeal of the PPTA and amendments to the CITA to enable its application to the operations of upstream petroleum companies.

Other significant aspects of the new fiscal regime proposed by the PIB include:

i. The introduction of a general production allowance (GPA) claimable by a company which has executed

[40] The Petroleum Industry Bill 2012

a PSC with NNPC. Under the current regime, an oil producing company which had executed a PSC with NNPC prior to 1 July 1998 is entitled to claim an investment tax credit (ITC) at the rate of 50% of qualifying capital expenditure (QCE) incurred by that company wholly, exclusively and necessarily for the purposes of its petroleum operations while an oil producing company which executed a PSC with NNPC after 1 July 1998 is entitled to claim the investment tax allowance (ITA) also at the rate of 50% of QCE. The difference between ITC and ITA is that while ITC offers a dollar for dollar credit which directly reduces the tax payable, ITA operates to reduce taxable profits before the tax rate is applied to determine the tax payable. The PIB now proposes to replace both ITC and ITA with GPA. Given that the GPA is intended to, much like the current ITA, reduce assessable profit (and not the tax payable), it is likely to impact more adversely on the take of PSC Contractors in the pre-1 July 1998 PSCs.

ii. While the ITC and ITA are calculated as a percentage of QCE and available throughout the period of petroleum operations,GPA is to be calculated as follows:

(a) For onshore operations: the lower of US$30 per barrel or 30% of the official selling price (OSP) up to a cumulative maximum of 10 million barrels and the lower of US$10 per barrel or 30% of OSP for volumes exceeding 10 million barrels up to a cumulative maximum of 75 million barrels and then no more.

(b) For operations in the shallow water areas: the lower of US$30 per barrel or 30% of the OSP up to a cumulative maximum of 20 million barrels and the lower of US$10 per barrel or 30% of the OSP for volumes exceeding 20 million barrels up to a cumulative maximum of 150 million barrels and then no more.

(c) For operations in areas with bitumen deposits, frontier acreages and deep water areas: the lower of US$15 per barrel or 30% of the OSP up to a cumulative maximum of 250 million barrels per Petroleum Mining Lease and the lower of US$5 per barrel or 10% of the OSP for volumes exceeding 250 million barrels.

(d) For companies currently in a PSC with NNPC but which are not currently claiming either ITC or ITA: US$5 per barrel or 10% of the OSP for all production volumes.

Oil producing companies in joint venture operations with NNPC are not entitled to claim GPA despite their entitlement to claim Petroleum Investment Allowance under the current regime. The PIB further proposes detailed provisions regarding the entitlement of gas producing companies to GPA.

iii. NHT is not deductible when calculating companies income tax (therefore constituting it as “true tax”). Similarly, the amount of companies income tax paid or to be paid is also not deductible in the computation of NHT.

iv. Unlike under the current regime, interest expense on loans obtained by PSC contractors to fund petroleum operations will not be an allowable deduction under the PIB.

v. All general, administrative and overhead expenses incurred outside Nigeria in excess of 1% of the total annual capital expenditure cannot be deducted in the computation of the adjusted profits of a company under the PIB. Further, 20% of any expense (other than the general, administrative and overhead expenses recoverable to the limit of 1% of total annual capital expenditure) cannot be deducted in computing adjusted profits except where such other expenditure relates to the procurement of goods or services which are not available domestically in the required quantity and quality and the approval of the Nigerian Content Development and Monitoring Board has been first sought and obtained. This provision clearly is aimed at promoting local content in the Nigerian oil and gas industry.

vi. The PIB also proposes to disallow :

(a) Legal and arbitration costs incurred by a company in cases against the tax authorities and the Nigerian Government; and

(b) Costs or fees incurred in obtaining and maintaining a performance bond under a PSC, in the computation of the adjusted profits of a company.

vii. The PIB proposes to re-enact the current provisions of the law which state that expenditure incurred in the acquisition of rights in or over petroleum deposits will qualify as "qualifying drilling expenditure" for which capital allowance at the appropriate rate may be claimed. In making this proposal, the PIB undermines the contention in certain Government quarters that signature bonus (which is the consideration paid to acquire a right in or over petroleum deposits) is not subject to capital allowance.

The PIB proposes provisions which put it beyond doubt that a PSC contractor which finances the cost of acquisition of a capital asset is entitled to claim capital allowances on the capital asset. In this regard, the PIB provides as follows:

"Where the production sharing contract between the national oil company and a contractor provides for the contractor to finance the cost of equipment and for such equipment to become the property of the national oil company, the contractor shall be deemed to be the owner of the qualifying expenditure thereon, for the purpose of the claim of capital allowances."

Indeed, the effect of this provision is that unlike under the current regime where the PSC Contractor and NNPC share in the benefit of capital allowance, only the PSC Contractor will be entitled to capital allowances under the PIB since the "contractor shall be deemed to be the owner of the qualifying expenditure thereon, for the purpose of the claim of capital allowances".

viii. It is proposed under the PIB that all upstream petroleum producing companies shall remit, on a monthly basis, to the Petroleum Host Community Fund (PHC Fund), 10% of net profits from their onshore, shallow water and deep water operations. The PHC Fund is to be utilised for the development of the economic and social infrastructure of the communities in which petroleum operations are conducted. Regarding contributions from operations in the deep offshore, these are to be utilised for the benefit of the littoral states. "Net profit" is defined in the PIB as "the adjusted profit less royalty, allowable deductions and allowances, NHT and companies income tax." Under the current regime, all producing and gas processing companies operating onshore and offshore in the Niger-Delta area are required to contribute 3% of their total annual budget to the Niger-Delta Development Commission Fund (NDDC Fund) pursuant to the Niger-Delta Development Commission (Establishment) Act (NDDC Act). Given that the NDDC Act is not one of the statutes listed for repeal under the PIB, it would seem that the intention is that the obligations to contribute to the PHC Fund and the NDDC Fund would co-exist. The fiscal impact of contributing to the PHC Fund would appear however to be ameliorated by the proposal in the PIB that contributions to the PHC Fund will constitute an immediate credit to a contributing company's total "fiscal rent obligations" which is defined as "the aggregation of royalty, Nigerian Hydrocarbon Tax and Companies Income Tax obligations arising from upstream petroleum operations". While the words "will constitute an immediate credit to a contributing company's total "fiscal rent obligations" suggests that the quantum of a company's royalty, NHT and companies income tax liability will be reduced by the amount of that company's contribution to the PHC Fund, it is not clear that this is what the drafters of the Bill intended. This is because the PIB also proposes that contributions made to the PHC Fund will be an allowable deduction in computing the NHT. It seems quite unlikely that the Government would approve a proposal which allows contributions to the PHC Fund as a deductible item in computing the NHT while also allowing the amount of those contributions to reduce the quantum of fiscalrent of which NHT is a part.

ix. With respect to royalties, the PIB does not specify new royalty rates, but provides that applicable royalties will be determined by regulations that will be drafted by the Minister after the Bill is enacted as law. However, pursuant to the savings provisions of the Bill, the present rates of royalties (which are charged on a sliding scale and are depth related) will continue to apply pending the issuing of new regulations by the Minister.

x. It should be noted that the PIB has not yet been passed, and that it has been in existence for a number of years. There has been a significant amount of opposition and voiced concerns from various stakeholders as to the content of the PIB and it is still not yet clear when the obstacles can be overcome sufficiently to allow it to be passed into law in the near future. The main issues that have been raised relate to the discretionary powers of the Minister (which appear to contradict the objective of increased transparency), the effect and structureof the PHC Fund (and, in particular, the way it will or will not be shared amongst the various Nigerian states), and the level of taxation (whereby the IOCs are claiming that the proposed rates will make most potentialnew investments uneconomic, especially in the gas sector).

## Major Players

The major international players in Nigeria's oil and natural gas sectors are Shell, ExxonMobil, Chevron,Total, and Eni.

NNPC has JV arrangements and/or PSCs with Shell, ExxonMobil, Chevron, Total, and Eni. Other companies active in Nigeria's oil and natural gas sectors are Addax Petroleum, ConocoPhillips, Petrobras, Statoil, and several Nigerian companies. IOCs participating in onshore and shallow water oil projects in the Niger Delta region have been affected by the instability in the region. As a result, there has been a general trend for IOCs to sell their interests in marginal onshore and shallow water oil fields, mostly to Nigerian companies and smaller

IOCs, and focus their investments on deepwater offshore projects and onshore natural gas projects. Nigeria plans to have a licensing round for marginal onshore and shallow water fields in 2014. The licensing round will consist of 31 fields being sold off by IOCs, according to IHS CERA. IOCs divesting from some of these projects include Shell,ConocoPhillips, and Chevron.

### Shell

Shell has been working in Nigeria since the 1930s. In the upstream sector Shell operates in Nigeria through the Shell Petroleum Development Company of Nigeria Limited (SPDC) and the Shell Nigeria Exploration and Production Company Limited (SNEPCo). SPDC is one of the largest oil and gas companies in Nigeria. SPDC has a JV with NNPC that is made up of NNPC (55%), Shell (30%), Total Exploration and Production Nigeria Limited (10%), and Nigerian Agip Oil Company Limited (Eni) (5%). SPDC's operations include:

- a network of pipelines,
- eight gas plants,
- two oil export terminals.

Shell's offshore activities are carried out by SNEPCo, which was formed in 1993 to develop Nigeria's deepwater offshore oil and gas resources. Under a PSC with NNPC, SNEPCo owns shares in three deepwater blocks; Bonga (Shell-operated), Erha/Erha North(ExxonMobil-operated), and Zabazaba/Etan (Eni-operated).

Shell, through its subsidiary Shell Gas B.V., holds a 25.6% interest in Nigeria LNG Limited(NLNG). NLNG operates six liquefaction trains at the Bonny facility with a total capacity of 22 million tons per annum (mtpa), or 30 billion cubic metres (Bcm) per year . Gas supplies for the LNG facility come from several oil and gas fields operated by Shell, along with fields operated by the other NLNG partners, Total and Eni. Shell provides the LNG facility with gas from its onshore projects Gbaran-Ubie, Soku, and Bonny and its offshore projects Bonga and EA.

Shell's onshore oil production has been affected by the instability in the Niger Delta region. Shell has temporarily shut in portions of its production several times over the past decade, while declaring force majeure on oil shipments, as a result of frequent sabotage to pipelines. Some of Shell's onshore/shallow water oil production capacity still remains shut in. From 2010 to mid-2013, Shell, through SPDC, has sold its share in eight onshore licences. In June 2013, Shell announced that it would initiate a strategic review to consider the potential divestment in the interests it holds in some onshore leases in the eastern Niger Delta. The company also indicated that it may sell its share in major pipelines. Shell has not indicated any plans to sell its deepwater offshore oil projects or its onshore natural gas projects in Nigeria.

**ExxonMobil**

ExxonMobil operates in Nigeria through its subsidiary Mobil Producing Nigeria (MPN) with a JV arrangement with NNPC. MPN has a 40% stake in the JV, and NNPC holds the remaining 60%. ExxonMobil also operates in Nigeria through its affiliate Esso Exploration and Production Nigeria Limited (EEPNL), which has a PSC with NNPC.

Most of ExxonMobil's projects are located in the deepwater offshore, making them less vulnerable to oil theft attempts. The company's largest assets in Nigeria include Qua Iboe, which is a crude blend produced from several offshore fields in the Bight of Bifra, and the Erha/Erha North deepwater project. Qua Iboe is Nigeria's largest exported crude blend, and production averages around 400,000 bbl/d, according to ExxonMobil. ExxonMobil also holds a 30% interest in Nigeria's newest producing deepwater field Usan, which is operated by Total. ExxonMobil produces natural gas liquids from the Oso Natural Gas Liquids project and the East Area Natural Gas Liquids project 2.

**Chevron**

Chevron, through its subsidiary Chevron Nigeria Limited, holds a 40% interest in 13 concessions under its JV arrangement with NNPC. Chevron produces natural gas and the Escravos crude oil blend from several onshore and shallow water fields located in the Niger Delta. The pipeline network transporting Escravos crude is often subject to pipeline damage from oil theft. As a result, Chevron announced in June 2013 that it will sell its 40%interests in five onshore/shallow water leases. Chevron, like its counterparts, is focused on deepwater offshore projects and onshore natural gas projects. Some of Chevron's largest oil projects are the Agbami field off the coast of the Niger Delta, which it operates, and the Usan deepwater field operated by Total, which Chevron owns a 30% share. The company also plans the start-up of the 33,000 bbl/d Escravos Gas to Liquids (GTL) plant, which is expected to come online within a year. Chevron is also the largest shareholder (36.7%) of the West African Gas Pipeline Company Limited, which owns and operates the West African Gas Pipeline. The pipeline transports gas from Nigeria to customers in Benin, Togo, and Ghana.

In 2012, Chevron restored natural gas production at some of its onshore leases. The Onshore Asset Gas Management (OAGM) project consists of the restoration of facilities that were destroyed in 2003 during civil unrest. It includes six onshore fields, and it is designed to supply the domestic market with 125 million cubic feet per day (MMcf/d) of natural gas.

**Total**

Total has participated in Nigeria's oil and natural gas industries since the 1960s and currently has multiple subsidiaries that participate in the oil and gas sectors. Total operates mostly deepwater offshore fields and a smaller number of onshore fields that are linked to Shell's Bonny export terminal. Some of Total's largest projects include the Amenam, Akpo, and Usan deepwater oil fields. Natural gas is also produced at onshore fields, known as the Obite Gas Project, and it is sent to Nigeria's LNG plant at Bonny. Associated gas from the offshore Amenam field is also transported to the Bonny LNG plant, and the field is the hub of Total's gas supply network to the LNG facility. Total owns a 15% stake in NLNG, the company that operates the LNG plant at Bonny.

Total also has a 17% interest in Brass LNG Limited, a consortium that is developing the Brass LNG Liquefaction Complex. According to Total, engineering work is still in progress. The complex is expected to have two liquefaction trains with a total capacity of 10 MMtpa (480 Bcf/y). The other members in the consortium include NNPC (49%), ConocoPhillips (17%), and Eni (17%).

### Eni

Eni, through its subsidiary Agip, produces oil in both onshore and offshore areas of the Niger Delta region. According to Eni, its operations are regulated by PSCs and concession contracts. A large portion of Eni's production comes from onshore fields that produce the crude oil blend called Brass River. A portion of Brass River is lost regularly to pipeline damage and oil theft. As a result, Eni has shut in varying volumes of production since 2006.

In 2012, Eni divested its 5% stake in three oil leases. Eni owns a 10.4% share in NLNG and a 17% share in Brass LNG Limited. The company participates in a number of onshore gas projects, including the Tuomo gas field, Gbaran-Ubie, and the Idu project, most of which feed the Bonny LNG facility. The company recently reduced the amount of gas it flared in Nigeria. According to Eni's 2012 annual report, 90% of the associated gas it produced in Nigeria was sold.

## Regulatory Structure

The Federal Ministry of Petroleum Resources (the Ministry) has overall regulatory oversight of the Nigerian oil and gas industry. The Ministry acts primarily through the Department of Petroleum Resources. Other regulatory bodies include the Petroleum Products Pricing Regulatory Agency, which regulates the rates for the transportation and distribution of petroleum products; the Federal Ministry of Environment, Housing and Urban Development, which is responsible for approving environmental impact assessment reports in respect of oil and gas projects; the Nigerian Content Development and Monitoring Board, which is responsible for ensuring compliance with the NCA; and the Joint Development Authority, which is responsible for the supervision of petroleum activities within the Nigeria–São Tomé and Príncipe Joint Development Authority. NNPC also has regulatory roles that it performs through the Department of Petroleum Resources.

The PIB will change the role of NNPC. Currently all NNPC’s revenues arising from the management of federal Government assets flow directly to the Federation Account and its funding for the JVs is then provided by the Government. This role will now be taken over by the Asset Management Company which will be capitalized with a two year loan in place of the annual cash calls and would later be expected to be self-financing through the retention of its earnings. All royalty and taxes would, however, be paid to the Government as and when due.

The new National Oil Company will broadly consist of the PSC assets which shall be used to capitalize the National Oil Company, the National Petroleum Development Company (NPDC), the current three domestic refineries (WRPC, KRPC and PHRC) and the Pipelines and Products Marketing Company (PPMC).

The new National Oil Company will also be partially privatized. It is expected that up to 30% equity shall be divested to provide private participation, similar to the strategy adopted by other NOCs such as Petrobras (Brazil), PETRONAS (Malaysia), etc. The Government expects the partial privatization to provide a culture change to a fully accountable and commercial company.

Along with the unbundling of NNPC, two new regulatory institutions; upstream petroleum, and downstream petroleum inspectorates are to be created to promote effective regulation and monitoring in line with international best practices. These regulatory entities are expected to perform both commercial and technical regulation in the upstream and downstream petroleum sectors respectively.

Nigeria’s quest to grow its reserves will be engendered in the proposed new PIB through a robust acreage management system to be superintended by the Upstream Petroleum Inspectorate. Similarly, the PIB proposes the establishment of a Technical Bureau in the Ministry of Petroleum Resources charged with the responsibility for frontier exploration services.

Over the years, Nigeria has underexploited its bitumen resources. The Frontier Exploration Services will provide necessary coordination and preliminary work for the Upstream Petroleum Inspectorate, which will through its acreage management system offer opportunities for investors. In order to underpin this, the PIB incorporates a fiscal regime for these frontier areas and specifically incorporates bitumen under the upstream fiscal framework.

Additionally, as described above a PHC Fund is proposed in the PIB. The Fund is a mechanism to formally recognize host communities as important stakeholders by assigning oil and gas infrastructure security to the host communities and minimizing environmental degradation due to vandalism and crude oil theft. As a freedom to operate tool, it incorporates penalties to host communities in the event of vandalism in their localities. The proposed legislation includes modalities for using regulations to increase flexibility in managing host community issues. However, there is opposition to the Fund from other Nigerian states that would not constitute host communities.

## *Trinidad and Tobago*

Trinidad and Tobago is one of the world's foremost natural gas economies. As of 2013 it produced 4.3 billion cubic feet of natural gas per day (bcfd) and 83,000 barrels of oil per day (bbl/d).[41] It is currently the world's sixth largest exporter of Liquified Natural Gas (LNG), exporting to 19 countries including Argentina, Brazil, Chile, the United States, Spain and Asia. Despite the transportation costs to Asia, attractive prices in the Pacific Basin make it a worthwhile export market. In 2011, the energy sector accounted for 40% of GDP, 80% of exports and 58% of fiscal revenues in Trinidad and Tobago. Exploration and production accounted for 61% of the energy sector's GDP between 2006 and 2010.[42]

### Exploration history

Trinidad and Tobago has a long history in the oil and gas sector. Commercial production of oil began in 1908, while exploration had began with geological surveys between 1855 and 1860. The Merrimac Company first discovered oil in 1857 after drilling a 280 foot well. This was followed by several more oil finds before oil exploration activity slowed and the sector became dormant. The sector became active in the early 20th century, when commercial production began in 1908 and exports in 1910. A refinery was also extablished in the same year, and by 1919 Trinidad and Tobago's refinery capacity was 9,000 bbl/d.

Large scale developments came with the entry of the first oil major in 1913; Royal Dutch Shell. By 1919, 66% of crude oil produced was refined locally, establishing a history of local value addition and spin-off industries.

#### Initial gas flaring and stimulating demand thereafter

Before 1975, hydrocarbon sector development focused on oil exploration and production, while associated natural gas was mostly flared, with some re-injected for enhanced oil recovery. During this time the required infrastructure and demand to monetise natural gas took a secondary focus to oil exploration and production. In 1953, Trinidad and Tobago Electric Company commissioned its first gas-fired power station, to add to its oil products (diesel) based generating plants. The Penal Power Station was supplied by a one and a half mile pipeline connecting the plant to Shell's Penal oil field. Despite this, demand for natural gas remained low, and flaring of gas remained commonplace.

In 1971, commercial quantities of natural gas were discovered off the north coast of Trinidad. By 1972 commercial production had began at Amoco's Teak platform. Several gas discoveries in quick succession spurred the Government to encourage natural gas exploration, use and downstream applications. Between 1975 and 1991, the State invested in the establishment of industries to create demand for natural gas including four ammonia plants, one urea facility, an iron and steel mill, a methanol plant and a natural gas liquids extraction facility. Since 1975 natural gas production in Trinidad and Tobago has increased steadily from 1.3 million tonnes in 1975 to 38.6 million tonnes as at 2013.[43]

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[41] E. Pickrell, Trinidad energy minister touts 'world's first natural gas economy', *Fuel Fix*, (2013), http://fuelfix.com/blog/2013/11/03/trinidad-energy-minister-touts-worlds-first-natural-gas-economy/

[42] ICF International, *The Future of Natural Gas in Mozambique: Towards a Natural Gas Master Plan*, (2013)

[43] Bp.com, *BP Statistical Review of World Energy June 2014*, (2014), http://www.bp.com/content/dam/bp/pdf/Energy-economics/statistical-review-2014/BP-statistical-review-of-world-energy-2014-natural-gas-section.pdf

## Licencing Regime

### Impact of Land law on the licencing process

In Trinidad and Tobago there is a distinction between the licensing for public and private petroleum rights. Licences under public petroleum rights are issued for 6 years and renewed for 19 years in the event a commercial discovery is made. Licences under private rights are issued for 20 years, but are subject to additional terms negotiated with the owner of the private petroleum rights.

### Private petroleum rights

In the late Nineteenth and early Twentieth century some land allocations by the State to private persons included all sub-surface rights not specifically retained by the State. This land ownership system has resulted in some petroleum rights being owned by private persons. These private owners sometimes sell their property while still retaining the sub-surface rights; therefore private petroleum rights are not always owned by the same person holding the surface rights. To carry out exploration and production operations involving private petroleum rights, the consent of the owner of the private petroleum rights is required, in addition to obtaining an Exploration and Production Licence from the Minister of Energy. Contracts with private owners take the form of private oil mining leases which provide for the payment of rents and/or royalties. This adds complexity and cost to the economics of oil production.

This complexity has since been eliminated in the issue of new land rights, although some private petroleum rights still exist for land issued in prior periods. Therefore, private land can either have private or public associated petroleum rights.

### Public petroleum rights

With public petroleum rights, one need only deal with the Ministry of Energy as these rights are vested in the State. State owned land, offshore areas and private lands where the sub-surface rights have been reserved to the State have public petroleum rights. The majority of land in Trinidad and Tobago carries public petroleum rights.

Petroleum activities over areas that are subject to public petroleum rights are carried out either under the authority of an Exploration and Production Licence granted by the Minister or by the Minister entering into a Production Sharing Contract (PSC) with the contractor. Exploration and Production Licences are essentially concessions, with minimum work obligations and a royalty structure. As per the Petroleum Act, a PSC is defined broadly as any other contract the Minister enters into relating to the exploration and production of petroleum under terms that the Cabinet has approved.

The Minister of Energy is responsible for determining the areas to be made available for petroleum operations. The State, through the President, may decide whether applications for oil and gas exploration on blocks identified by the Minister should be made on a competitive bidding basis or not. However, competitive bid rounds are now general practice for offshore marine areas and have been used for onshore areas as well.

### Trinidad has several licencing regimes for upstream operations

There are 4 main licensing regimes in Trinidad and Tobago, with the first three being concession based:

- An Exploration and Production Licence (Public Petroleum Rights) on **a non-exclusive** basis for a given area;
- An Exploration and Production Licence (Public Petroleum Rights) on an **exclusive** basis for a given area;
- An Exploration and Production Licence (Private Petroleum Rights) on a non-exclusive basis for a given area; and,
- A Production Sharing Contract (PSC) for operations over a prescribed area.

It is up to the potential developer to put together an appropriate proposal within this framework for a given acreage. In the case of competitive bid rounds, the Ministry specifies key terms, for example state company participation via a Joint Venture/Joint Operating Agreement with the successful bidder, and subjects other specifics to the bidding process.

In the event a competitive bid round involves state enterprise participation, the Ministry of Energy names the Petroleum Company of Trinidad and Tobago Limited (Petrotrin), a state owned company and Trinidad and Tobago's largest oil producer, as the entity to be involved in the development of the relevant block alongside the winning bidder. Petrotrin does not have a regulatory role unless it has sub-licensed acreage it owns, and that is in turn regulated by the Ministry of Energy as primary regulator. Petrotrin is the largest crude oil producer in Trinidad and Tobago and owns the only petroleum refinery. It is 100% state owned. In crude oil production, the largest players are Petrotrin, followed by BP Trinidad and BHP Billiton. About 20% of crude oil production is consumed domestically.[44]

In the case of natural gas, National Gas Company (NGC), another state owned company, has a monopoly on the purchase, distribution, and marketing of natural gas within the country. However, both the exploration and production and the export of natural gas is liberalised.

In 2011, the top three companies in terms of natural gas production were BP, BG and EOG with 55%, 24% and 12% respectively. Other firms including BHP Billiton, Repsol and Petrotrin accounted for 9%. As of 2010, production of natural gas by all state owned companies totalled only 3%.[45]

In 2010, LNG for export accounted for 58% of natural gas use, domestic ammonia and methanol production accounted for 15% and 14% respectively. With a population of about 1.4 milion people , domestic power generation accounts for only 7% of natural gas use although 98% of electricity is currently produced using natural gas. [46]

From 2004 to 2011, LNG exports to the U.S. decreased from 99% to 19%, as a result of U.S. domestic shale gas production. European, Asian and South American exports increased as a result, with Europe now accounting for 40% of Trinidad's gas exports.[47]

## Commercial Structure

Key commercial terms in the exploration and production of natural gas are largely negotiated and vary between competitive rounds, and from contract to contract. In the recent November 2013 competitive round that involved three onshore and six offshore blocks, successful bidders for the onshore blocks were to be issued with E&P licences and enter into a joint operating agreement (JOA) with Petrotrin. Petrotrin took a 20% carried interest in the resultant onshore ventures, with the successful bidders financing all minimum work obligations, and all financial obligations during the exploration period. This arrangement effectively shields Petrotrin from any exploration risk, as any investment by Petrotrin will be in the production phase. The six offshore blocks were offered under PSCs, with no state participation in the development of assets beyond receiving the Government share of profit petroleum as per the terms of the PSC.

### Royalty and Tax structure (E&P and PSC):-

Oil and Gas:-

- Royalty rates for oil and gas range from 10- 15% for both onshore and offshore production (Royalties only apply to E&P licences).
- Corporation tax (Petroleum Profits Tax) charged at a rate of 50% of gross revenues from all sources less

[44] Inter-American Development Bank, *Trinidad and Tobago's Energy Market*, (2014), http://blogs.iadb.org/caribbean-dev-trends/2013/12/02/trinidad-and-tobagos-energy-market/
[45] V. Mercer-Blackman,*Tax Regimes in Hydrocarbon-Rich Countries: How does Trinidad compare?*, University of The West indies, (2014), http://sta.uwi.edu/conferences/12/revenue/documents/Tax_regimes_in_hydrocarbon-rich_countries-MercerBlackman.pdf
[46] Ibid.
[47] E. Pickrell, Trinidad energy minister touts 'world's first natural gas economy', *Fuel Fix*, (2013), http://fuelfix.com/blog/2013/11/03/trinidad-energy-minister-touts-worlds-first-natural-gas-economy/

deductible expenses and allowances.For deep water acreages the tax rate is35%. Cost recovery limits are fixed at 50%, 55% & 60% for shallow, average and deep water-depth acreages, respectively. In earlier PSCs, these limits were biddable terms.

- There is also an Unemployment Levy of 5%, with some deductions allowed.
- Under a PSC, the contractor is exempted from paying oil and gas royalties, however the Government share of profit petroleum is not deductible for tax purposes.

Oil only:-

- Crude oil attracts a 3% Petroleum Production Levy, to subsidise petroleum products sold domestically.
- A Supplemental Petroleum Tax (SPT) is levied on crude oil based on prevailing prices (0% for crude oil prices under US $13.01/bbl to a maximum of 35% for prices over US $49.50/bbl). As of 2011, this has been amended to eliminate SPT for oil prices below US $ 50/bbl and is calculated net of royalties.
- 20% discount on SPT or 20% credit on capital expenditure for small and mature offshore fields for the application of 'enhanced oil recovery" (EOR) methods (companies can choose the incentive they prefer)
- Under a PSC, the contractor is exempted from paying SPT, and Petroleum Production Levy for oil.

In order to promote downsteam industries like power generation, NGC purchases natural gas cheaply from producers, therefore providing a low cost feedstock to domestic downstream industries. This system is effectively an additional tax on upstream natural gas companies.

In total, income taxes and royalty payments attributed directly to the oil and gas sector accounted for 37.2% of total Government revenue. Including various other taxes, levies, and fees associated with the energy sector, the Trinidad and Tobago Ministry of Energy estimates the Government's total take from the hydrocarbon sector is closer to 50%of total revenue.[48]

According to the Inter-American Development Bank (IDB), Trinidad and Tobago's taxation on the oil and gas sector is slightly above average, however IDB believes this is offset by the political stability of the country.

### Regulatory Structure

The petroleum industry, Trinidad and Tobago's largest industry, is governed by the Petroleum Act and the Petroleum Regulations which establishes the process for granting of Exploration and Production Licences and PSCs for both onshore and offshore operations. The Act and Regulations cast the regulation net wide and no activities may be conducted without Government approval. The primary regulator of the industry is the Ministry of Energy.

E&P Licences and PSCs normally provide for multiple dispute resolution options including mediation, expert determination and/or arbitration which generally specify Trinidad and Tobago as the seat and its laws as the governing law.

However, disputes are virtually always settled by negotiation and discussion.

Prior to 1998 NGC, acting on behalf of the Government, negotiated terms on a case by case basis. As a result contractual terms were varied. With development of the sector recommendations from the Governement's 1998 Green Paper on Energy were implemented, standardising royalty rates for natural gas along the lines of models adopted by Thailand, Malaysia and Chile.

Other key legislation relating to the oil and gas sector includes The Petroleum Production Levy and Subsidy Act, and The Petroleum Taxes Act. The Petroleum Taxes Act and supporting legislation, allowed deductions for the following:

- capital expenditures
- royalties
- Supplemental Petroleum Tax

[48] ICF International, *The Future of Natural Gas in Mozambique: Towards a Natural Gas Master Plan*, (2013)

- the Petroleum Levy
- decommissioning costs
- management fees paid to non-residents (not exceeding 2 percent of expenses) of income
- allowances for dry holes, heavy oil as well as for signature and production bonuses
- accelerated depreciation to encourage investment

**Using oil and gas to improve national well being**

The State enforced certain levies and taxes to go towards the social and enviromental well being of the country. The Unemployment Levy Act levies a rate of 5% of chargeable income on oil and gas companies only in order to aid social programs. As of 2001 there is also the Green Fund Levy under the Miscellaneous Taxes Act.This levy is computed as a percentage (currently 0.1%) of the gross sales or receipts, and these payments are not tax deductible and are intended for environmental restoration and preservation efforts.

**Preserving hydrocarbon wealth for future generations**

In 2004, Trinidad and Tobago established a Heritage and Stabilization Fund (HSF) as a savings vehicle to allow for countercyclical fiscal policy and shield the economy from the effects of the energy commodity cycle. This Fund was created out of the Revenue Stabilization Fund which had been in existence from 2002.

Just prior to the global financial crisis, the Heritage and Stabilization Fund held assets of US $ 1.9 billion– a significant increase over the 2002 balance of just under US $ 500 million, suggesting average rates of deposit of approximately $250 million annually.[49] These assets have improved Trinidad and Tobago's credit profile and allowed its economy to weather the effects of the global financial crisis and declining Government revenue from the energy sector. Rather than drawing on the HSF as earlier envisioned, Trinidad and Tobago has been able to access capital from the international bond markets.

[49] Ibid.

# Ghana

The 2007 discovery of the Jubilee Field in the Deepwater Tano and West Cape Three Points blocks gave significant impetus to the upstream sector in Ghana. Ghana's recoverable reserves are currently estimated to be in the range of 0.66 billion barrels and its gas reserves to be approximately 0.8 Trillion Cubic Feet (Tcf) (approximately 22.6 Bcm)[50]

Commercial production from the Jubilee Field started in December 2010 and is currently reported as between 70,000 and 90,000 b/d, with the field partners anticipating an increase to 120,000 b/d by mid-2013. In addition to ongoing development work on the Jubilee field by the Jubilee partners, Eni has announced that it is planning to proceed with the Sankofa Oil and Gas field development. Companies now active in blocks offshore Ghana include Eni, Hess, Afren, Saltpond Offshore Production, Vitol, Gasop Oil, Oranto Petroleum, Vanco Ghana Limited, Lukoil, Kosmos, Tullow, Tap Oil and Anadarko.

In relation to natural gas, the Ghana National Gas Company (GNGC) has been set up to implement the Gas Infrastructure Project.

## Exploration history

In July 2007, Tullow Oil and Kosmos Energy discovered oil in commercial quantities in the western region of Ghana. They named the area "Jubilee Field". Development of the production site started right away and in December 2010 oil production was officially launched. Since 2007 further discoveries have been made including the Tweneboa field.

The Ghana Government, with the aim of owning the reserves when the discovery was made, decided to fund the exploration activities. This approach by the Government towards the exploration was not successful due to the high cost associated with the exploration.

However, in 2001 the Government of Ghana decided to move away from the nation-centric approach to an all-inclusive approach which served as an incentive to participation of private oil companies. In 2003, the Government enacted changes in taxes and other levies on oil production which led to the involvement of several major international oil and gas firms like Tullow, Kosmos and Gasop. Notably, with the involvement of private interest groups alongside a re-equipped GNPC, new discoveries of oil and gas in commercial quantities were made by both Kosmos and Tullow in what is known as the Jubilee field. Indeed other discoveries have since been made and are also being developed. When oil was discovered in large quantities in Ghana, the Government embarked on a stakeholder engagement process to get a view on how best the oil and gas resources could be of greater economic benefit.

## Licensing Regime[51]

### Open door policy

Under the Petroleum Law, the Minister of Energy has the power to divide Ghana into a number of blocks and enter into petroleum agreements in respect of these blocks. Apart from GNPC, no person is allowed to engage in petroleum exploration, development and production without entering into a petroleum agreement with GNPC and the Government of Ghana (represented by the Minster of Energy). The Minister may establish a competitive bidding procedure for the award of petroleum agreements but awards of petroleum rights have, to date, been via the 'open door' policy rather than through competitive licensing bid rounds.

[50] US Energy Information Administration website
http://www.eia.gov/countries/country-data.cfm?fips=gh
[51] Akyeampong J *The Petroleum Regime in Ghana*( 2009)
http://siteresources.worldbank.org/INTGHANA/Resources/PETROLUEM_LICENSING_AND_CONTROL.pdf

Any person who wishes to enter into a petroleum agreement for a particular block must submit an application to the Minister. The Petroleum Commission which is under the authority of the Minister of Energy is now technically responsible for administering the application process, which involves reviewing, evaluating and making recommendations for the award of petroleum agreements. However, as a matter of practice, GNPC continues to be involved in the review and negotiation of the terms of draft Petroleum Agreements.

Some of the key criteria considered in any application include the financial capability, technical track record, the proposed work programme, the proposed budget, and fiscal terms proposed by the applicant. Once the Petroleum Commission's recommendations for the award of licenses are accepted and the terms of the petroleum agreement are negotiated, the draft agreement is sent to the cabinet for approval. After cabinet approval, the agreement is executed by the parties and sent to parliament for ratification. There is no mandated timetable for approvals

The Petroleum Law prescribes a number of matters that must be included in any petroleum agreement. A Model Petroleum Agreement has been created incorporating, among other things, the matters prescribed by the Petroleum Law, and this forms the basis of negotiations with contractors. One of the basic requirements is that a contractor must incorporate or register a company in Ghana under the Companies Act, 1963 (Act 179) to carry out petroleum operations in Ghana. This entity must be the signatory to the petroleum agreement and must maintain an office in Ghana.

The Model Petroleum Agreement prescribes an initial exploration period that may be extended up to two times, the total period not to exceed seven years. Following notice of a discovery and declaration of commerciality after appraisal, a development plan has to be submitted for approval by the Minister of Energy. The term of the Model Petroleum Agreement is not to exceed 30 years from the effective date.

## Commercial Structure

Pursuant to the Petroleum Agreement:

- The state is entitled to a percentage of the volume of crude oil (including condensates and distillates from natural gas) produced during development and production operations (excluding crude oil used for petroleum operations) as a royalty. The percentage is negotiable and depends on a number of factors: oil or gas resource, water depth, existing infrastructure, etc. The state can decide whether to take the royalty in kind or in cash.
- The state is entitled to an additional oil entitlement (AOE) in respect of each separate development and production area on the basis of the after-tax, inflation-adjusted rate of return (ROR) achieved by the contractor. This is calculated monthly and liability to provide the AOE starts once net cash flow for a month (revenues for the month, less one-twelfth of income tax due for the calendar year in question less petroleum costs) turns positive. The AOE escalates as the ROR increases and is subject to an inflation adjustment based on the United States Industrial Goods WholesalePrice Index;
- After deductions of volumes for royalty (if taken in kind) and AOE, the contractor and GNPC share volumes of petroleum in accordance with their participating interests;
- The contractor is required to pay Income Tax as stated in the Petroleum Income Tax Act. The prevailing rate is currently 35%. Older forms of the Model Petroleum Agreement stated that no 'tax,duty, fee or other impost' shall be imposed by the state or any political subdivision in respect of petroleum operations and the sale and export of petroleum, save as set out in Article 12. However, this provision has not been offered in more recent forms of the petroleum agreement;
- Exports of petroleum from Ghana are not subject to any tax or other duty; and,
- The contractor may import all plant,equipment and materials required for petroleum operations free of any customs or other duties or tax.

## Local content[52]

The Petroleum Law and the Model Petroleum Agreement contain provisions on local content requirements. Under the Petroleum Law, contractors and subcontractors must, as provided in regulations and a petroleum agreement or sub-contract so far as is possible:

- ensure that opportunities are given for the employment of Ghanaians with the requisite expertise or qualifications in the various levels of the operations;
- use goods and services produced or provided in Ghana for their operations in preference to foreign goods and services.

The Government of Ghana also prepared a Local Content Policy, which wil went further than the previous legislation. This required, among other things:

- up to 90 per cent of particular parts of petroleum operations to be provided by local companies;
- for Ghanaians to hold at least a 5 % equity interest in any oil and gas block; and
- for specified percentages of management positions and employees to be filled by Ghanaians.
- Ghanaian firms be given priority in the block's bidding process

All firms prepare a local content plan prior to bidding for blocks and chart a plan for local involvement

## Regulatory Structure

The Ministry of Energy is mandated to formulate, implement and evaluate policies for the energy sector as a whole. In line with this mandate, the 'Fundamental Petroleum Policy for Ghana' was published in June 2009. Under the Petroleum Law, the Minister of Energy is also responsible for, among other things:

- granting rights to explore for, develop and produce petroleum; and,
- granting consents to the transfer of rights to explore for, develop and produce petroleum.

The Petroleum Commission was created by the Petroleum Commission Act, 2011 (Act 821) with the objective of regulating and managing the use of petroleum resources and co-ordinating policies relating to them. The Petroleum Commission is designed to take over regulatory responsibilities relating to the upstream petroleum sector which were previously the preserve of GNPC, on behalf of the Ministry of Energy. The commission's functions include:

- ensuring compliance with health and safety and environmental standards;
- regulating petroleum operations;
- receiving applications and issuing permits for specific petroleum activities;
- promoting local content and local participation in petroleum activities; and,
- assessing and approving appraisal plans.

The Petroleum Commission is under the authority of the Minister of Energy and advises on policy. The Minister of Energy is also the arbiter in any disagreement between an Operator and the Commission (before any arbitration or court process is initiated).

[52] Petroleum Local Content and Local Participation Regulation(2013)

## National Oil Company

The GNPC was established by the Ghana National Petroleum Act 1983 (Act 64) with a mandate to, amongst other things, undertake the exploration, development, production and disposal of petroleum. GNPC is also granted certain rights under the Petroleum Law in respect of petroleum operations, including:

- the right to conduct exploration,development and production activities over all blocks for which a petroleum agreement does not exist and to enter into petroleum agreements with third parties to conduct such activities with them;
- the right in any petroleum agreement to an option, following a declaration of commercial discovery, to acquire a percentage interest in the rights and obligations under the petroleum agreement on terms to be agreed with the applicable contractors (see Licensing regime section below); and
- ownership of all data and information obtained from petroleum operations.

With the establishment of the Petroleum Commission, GNPC is now free to focus on its commercial role rather than having regulatory responsibilities.

The Model Petroleum Agreement grants GNPC an initial carried interest in all petroleum operations under the agreement. The percentage interest is negotiable. This initial interest is carried for exploration and development operations, but is a paying interest for production operations. Under section 17 of the Petroleum Law, any petroleum agreement must give GNPC an option, within 90 days of a commercial discovery being declared, to acquire from the contractor a further percentage interest in the discovery. Under the Model Petroleum Agreement, the percentage to be acquired is a biddable item and subject to negotiation. GNPC is required to fund its share of costs relating to its additional interest.

## *Israel*

Israel is surrounded by several nations that have over the years discovered vast petroleum reservoirs. Historically, the country enacted its petroleum legislation (Petroleum law) in 1952 to govern discoveries and activities in the sector, and this underwent substantial amendment in 1965. The producer is entitled to transport and market the hydrocarbons, but this is subject to the right of Government to call upon them to supply local needs first at a market price. The enactment of the Law was followed by the founding of a number of exploration companies as well as the creation of institutions providing professional support.

Key institutions that emerged following enactment of the Petroleum law include the Geophysical Institute of Israel, which carries out seismic and potential field surveys, and the Geological Survey of Israel, which provides outcrop studies and a variety of laboratory services.

### Exploration History

**Recent gas discoveries**

The county made its first petroleum discovery in 1955 in the Heletz field and other fields thereafter but despite this, the country did not become a significant petroleum producer as the fields yielded limited commercial volumes of hydrocarbons.

The country made significant progress a decade and a half ago with the discovery of large natural gas reserves in the Noa field and afterwards at the Mari B field. These discoveries and concerns over the reliance on pipeline imports from Egypt accelerated further exploration efforts which have since yielded significant discoveries. In 2009, discoveries were made in the Tamar field with an estimated 300 Bcm of gas reserves and in 2010 discoveries were made in the Leviathan structure with estimated reserves of 620 Bcm.

Production from the Tamar field began within four years after discovery in 2009 and production from the Leviathan field is set to begin in 2017, although this is still subject to satisfactory resolution of commercial and regulatory issues.

With these developments natural gas has become a primary source of energy for Israel in less than 10 years providing energy for electric generation, industrial use as well as private consumption.

### Stimulating demand[53]

The large gas discoveries have seen the State of Israel move away from the use of coal and oil generation plants for electricity generation and increased its electricity generation using natural gas. This has created a domestic demand for the resource whose use is largely in electricity generation. Local demand has previously been met by local production as well as supply from Egypt. The reliance on supplies from Egypt has however gradually reduced as Israel has continued to develop its domestic production from the new discoveries. Furthermore supplies from Egypt have been affected by disruption following the Egyptian uprising and the sabotage of main pipeline connecting gas supply between the two nations. Security of supply has now been reinforced by the development of an LNG import facility.

Despite these challenges electricity production from natural gas sources as a percentage of total production has increased significantly from 9.2% in 2004 (when gas first came onstream in Israel) to 37% by 2010 only experiencing a slump in 2011 and 2012 following supply disruptions during the Egyptian uprising. The country however anticipates increasing its electricity production from Natural Gas which is anticipated to increase to 50% by 2015.[54] This is attributable to production from the Tamar field commencing in 2013 and is expected to increase as production from the Leviathan field commences in a few years.

[53] R.Beckwith, "Israel Gas Bonanza", JPT/JPT Online,2011.
[54] Ministry of National Infrastructures ,Energy and Water Resources , (2014)*http://energy.gov.il/English/Subjects/Natural%20Gas/Pages/GxmsMniNGEconomy.aspx*

*Table L - 2: Electricity Production from Natural Gas sources as a percentage of total production*

| 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|---|---|---|---|
| 9.2 | 11.6 | 18 | 19.6 | 27 | 32.8 | 37.5 | 33.1 | 20.9 |

*Source: World Bank*

*The discussions below relate to natural gas.*

## Regulatory structure

The key regulatory authorities for the sector are as follows:

- The Ministry of National Infrastructure, Energy and Water Resources (Ministry of Energy) which establishes overall policy for natural gas exploration and production under the Petroleum Law.
    - The Ministry of Energy also supports local knowledge and capacity building. It operates three research institutes to study and develop natural resources, which were brought together in 2009, in a Government resolution, under the Earth and Marine Sciences Research Administration.
    - Regulation of activities in the natural gas sector are governed under the Natural Gas Authority within the ministry under the provisions of the Natural Gas Sector Law.
- The Ministry of Finance, which is involved in the development of fiscal policy and funding of large scale infrastructure under the Petroleum Taxation Law.

## Israel Government policy response to discoveries

Following significant gas discoveries offshore, the state of Israel has taken steps in setting policies governing activities in the sector to safeguard energy security, provide certainty to market players and fast track exploration activities.

Under the two key regulatory ministries the Government set up two committees to make fiscal and other policy recommendations for the sector. To ensure inclusion of market players, the process also involved stakeholder consultations.

The Minister of Finance on April 2010 appointed a committee known as the Sheshinki Committee to examine the fiscal policy for the oil and gas resources in Israel. Findings of the committee were publicly published to allow for stakeholder consultations with key industry players including gas companies, small investors and other associations.

Comments from stakeholder consultations were incorporated in the final recommendations from the committee that were passed into the Petroleum Taxation law in 2011.

### Fiscal policy recommendations – Commercial Structure[55]

Key fiscal recommendations adopted from the Shenshinki Committee include;

- Maintaining a 12.5% royalty rate;
- Instituting a progressive levy (20% - 50%) on cumulative revenues;
    - Levies are chargeable after deduction of project expenses including financing costs, royalties and previous levies;
    - The progressive levy would be chargeable at a ratio of 1.5 i.e. repayment of full investment plus 50% before tax;
- Increase of state share of profits from 33% to 52% - 62%;

[55] State of Israel , *Conclusions of the committee for the examination of the fiscal policy with respect to oil and gas resources in Israel,20111*

- The recommended policies also include incentives such as accelerated depreciation to increase cash flows for debt service for investors.

In 2011 the Prime Minister and the Minister of Energy and Water Resources appointed a second inter-ministerial committee to examine Government policy on the natural gas industry in Israel. Of particular importance was the development of an acceptable policy towards the export of natural gas, taking into account the projected future gas needs of Israel. After holding stakeholder consultations on its findings, the chairman of the committee submitted recommendations to the Prime Minister and to the Minister on August 29, 2012, which are yet to be approved.

**Natural gas policy recommendations - Domestic supply requirements56**

Key recommendations from the committee includes enforcing policies safeguarding Israel's future energy requirements:

- Enforcement of an export policy that guarantees a local supply of natural gas for energy needs for a period of 25 years (estimated aggregate demand of 450 BCM).
- Furthermore, the committee recommended that lease holders be required to acquire export licences authorized by the Minister of Energy and Water resources.
- In addition, the committee recommended that natural gas volumes permitted for exports be pre-determined to ensure that sales do not counter national interests. Furthermore Lease owners of gas fields be mandated to supply domestic market depending on the size of their fields as follows:
  - Gas fields with reserves more than 200 Bcm will supply at least 50% of the reserves domestically.
  - Gas fields with reserves between 100 -200 Bcm will supply at least 40% of the reserves domestically.
  - Gas fields with reserves between 25 -100 Bcm will supply at least 25% of the reserves domestically.
- To further ensure supply security the committee recommended the implementation of policy incentives that would promote the development of small fields (fields with volumes less than 25 Bcm) and attract investment. These incentives include no restrictions to supply natural gas domestically as is required from fields with volumes more than 25 Bcm as prescribed above.

Following further lobbying and debate in the Knesset, the final policy adopted is that 60% of large fields should now be retained for use in Israel, with only 40% allowed to go to export. This is thought to be the main reason why Woodside turned down their option to acquire a stake in the Leviathan field earlier this year.

## Licensing regime[57]

Licensing of exploration blocks is governed by Petroleum Law 1952 which establishes three primary types of rights;

- A Preliminary Permit is granted by application and allows the applicant to conduct preliminary exploration activities excluding test drilling to evaluate the prospects of natural gas production (up to 18 months).
- Following initial exploration activities a permit holder may apply for a licence to begin drilling exploration including test drilling (initially 3 years, extendable by a further 5 years). In some cases, preliminary investigations are conducted by the Petroleum Exploration Basic Research Company owned by the state in which case the granting of licences is by way of competitive bidding.
- Following discovery a licensee may then apply for a lease (30 years initially, extendable up to 50 years) for production within a specific area which is limited to two hundred and fifty thousand dunams. Leases for areas which no petroleum rights or application for already exist are granted by way of competitive bidding.

[56] Ministry of National Infrastructures ,Energy and Water Resources , (2012) *http://energy.gov.il/English/PublicationsLibraryE/pa3161ed-B-REV%20main%20recommendations%20Tzemach%20report.pdf*
[57] Ministry of Infrastructure and Water Resources , The Petroleum Law – Part 2 , http://energy.gov.il/English/PublicInfo/Pages/GxmsMniLegislationAll.aspx?WPID=WPQ4&PN=2

### Competitive bidding

In general licensing for petroleum exploration in Israel follows competitive bidding however holders of Preliminary Permits are granted rights to licence and leases in areas where the holders have conducted preliminary exploration. Rights to conduct activities as permitted by a licence and a lease are however limited to a defined area measured in dunams. The maximum area for a licence is 400,000 dunams (approximately 99,000 acres). No Licensee shall hold more than twelve licences. Furthermore the area for a lease is 250,000 dunams (approximately 62,000 acres). No lessee shall hold a lease for an area exceeding three million dunams. All other areas under which no right has been granted are assigned through competitive bidding.

### Time limits on exploration and production

To ensure that exploration activities are ongoing on land where exploration rights have been granted, the Petroleum Law sets time restrictions for exploration activities. Holders of licences are required to commence drilling within four months of receiving a licence while requirements for test drilling is set to be effected within two years of receiving a licence. Furthermore lessees are required to produce natural gas within three years of being granted a licence failure to which result in expiration of the lease.

## Major players

The State of Israel does not operate a national oil company. However, local companies as well as international companies take part in exploration activities. Some key local players include Delek Drilling LP, Avner Oil Exploration, Ratio Oil Exploration, Adira Energy, AGR Energy AS among others. The main international player and operator of the Leviathan, Tamar and Mari B fields is Noble Energy. Noble and its partners in Leviathan recently ran a tender process to find a suitable international partner to develop the field, which was assumed to include the export of LNG in which none of the existing partners had experience. Woodside Petroleum of Australia were successful in this process, but they recently announced that they would not be taking up their option for a stake in the field citing the unfavourable fiscal and policy regime that would apply to the development, as well as a possible move towards pipeline exports rather than LNG.

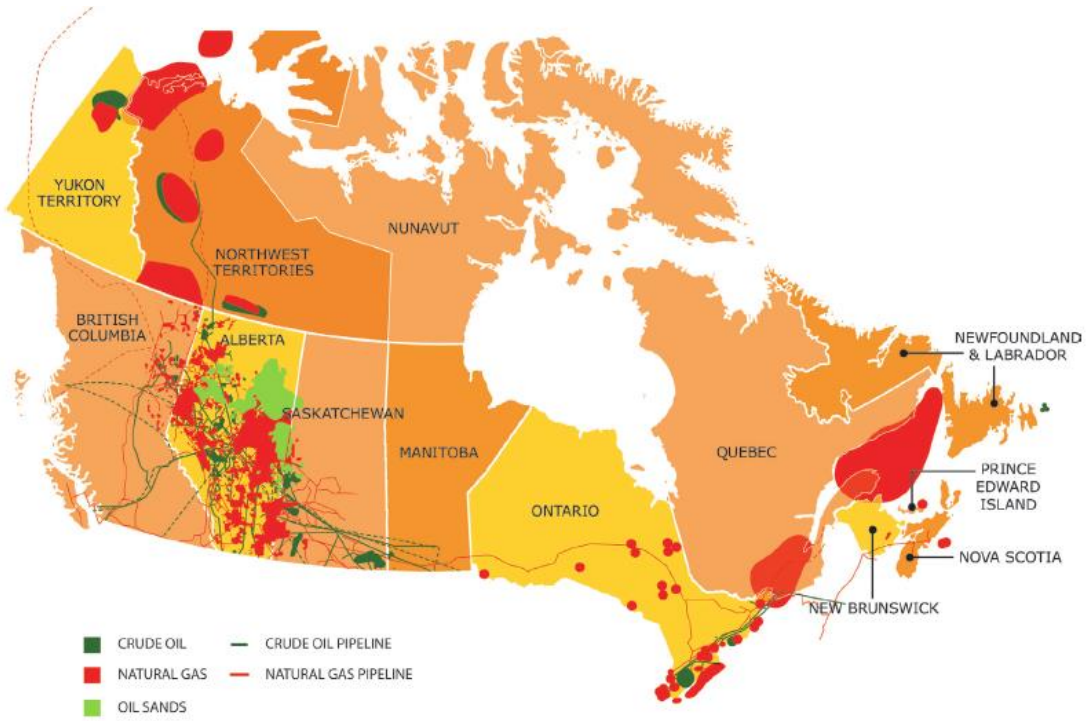
## Canada

The rise of the energy sector has largely contributed to the performance of the Canadian economy over the past decade. In terms of the total energy production, Canada ranks fifth in the world, behind only U.S., China, Russia, and Saudi Arabia. The past decade witnessed a massive increase in the investments related to oil production, particularly, the non-conventional production in oil sands. Canada has the potential to scale up its crude oil production upwards significantly considering the proven reserves which are estimated at 174.3 billion barrels—one of the largest in the world.

The country boasts of extensive oil and natural gas resources spread right across it and there are upstream activities in 12 of 13 provinces and territories. The country produces about 3.9 million barrels of oil per day with approximately six billion barrels of oil located outside the oil sands. These can be found primarily in Alberta, Saskatchewan and offshore Newfoundland and Labrador.

Canada is also home to a sizeable quantum of natural gas with a proven reserve base of about 2 trillion cubic metres (2013), particularly in British Columbia, Alberta and offshore Nova Scotia.

*Figure L - 1: Canada Oil and Gas Industry - Geography of resource endowments*




*Source: Canadian Association of Petroleum Producers*

## Exploration History[58]

### Initial period

Oil production commenced in Canada in the late 1850s and the industry was centered in Ontario for most of the next four decades. By the end of 19th century, activity patterns had begun to shift West, principally to Alberta. Ontario and Alberta remained the focus regions in Canada until 1946. The entire production was consumed within the province in which it was produced with no exports.

The massive oil discovery at Leduc, Alberta in 1947 provided a stimulus to Canada's modern petroleum industry. Within the next ten years, activities related to development and production of oil and gas spread to the provinces of British Columbia and Saskatchewan. By the end of the 1950s, a pipeline connecting Western Canada to major consumption markets such as Eastern Canada and the United states had also been built opening up avenues for gas monetisation.

The production capacities of these provinces grew rapidly. However in the 1950s, lower growth in the accessible consumption markets vis-à-vis the production levels resulted in the shut-in of production and downward pressure on well head prices. The Government of Alberta introduced a prorationing system which mandated the province's oil producers to assign individual quotas based on the productive capacity of their reservoirs, to share the impact of shut-in production with all oil producers. However, the production capacity of crude oil and natural gas continued to grow in Alberta and the sector needed Government involvement to ensure expansion of the consumption market and opportunities for oil and gas industry growth. The pipeline capacity augmentation connecting producing regions in Alberta to new markets in Ontario was completed in 1958 with the financial support from the Government of Canada. By 1960 about 20% of both crude oil and natural gas produced in Canada was exported to United States.

The federal Government of Canada facilitated this expanded penetration of consumption markets by allowing, under its constitutional powers, construction of these inter-provincial and international pipelines and also for export sales to occur. A National Energy Board in 1959 was created by the Federal Government to approve and regulate the construction and operation of inter-provincial and international pipelines and to regulate the exploration of oil and natural gas.

### Stimulating demand – 1961-1973

With excess production capacity experienced by oil producers in Western Canada, especially in Alberta, the Federal Government of Canada decided to introduce the National Oil Policy in 1961. The policy mandated Canadian consumers to the East of Ottawa Valley line (East of the border between Ontario and Quebec) to be supplied with oil products produced from imported crude, whereas giving Canadian producers exclusive rights to the areas to sell oil to the west of the line. Refineries to the east of the line could continue to process imported oil. The aim of the National Oil Policy was to promote Alberta's oil industry by securing for it a protected share of the domestic market. Opportunities for additional export sales in United States were also allowed to be pursued and pipeline capacity was allowed to rise commensurate with export volumes.

This federal policy initiative was widely supported by Canada's oil industry and the Governments of producing provinces in the West. By curbing imports to Ontario, the policy acted to boost the average price of Canadian produced crude oil. As a result, the oil production grew sharply to 1.8 million b/d in 1972 from a level of 0.55 million b/d in 1960. About 50% of the oil produced was exported to United States in 1972. However, oil production remained heavily concentrated in two provinces, Alberta and Saskatchewan (about 95%) and natural gas production remained heavily concentrated in Alberta and British Columbia (96%).

[58] Working paper on Oil and Gas in the Canadian Federation, Department of Economics, University of Alberta, 2010

**Federal policy on securing supply for future needs of the country – 1972 -1984**

Concerns over the adequacy of Canadian hydrocarbon reserves in meeting rising future demand resulted in fundamental changes in the Federal Policy of Canada. In 1973, the Government of Canada announced its intention to exercise its constitutional powers, first to curb oil and gas exports and second to regulate the prices of these commodities sold to the market outside the provinces of production to enhance the energy security in Canada and shield Canadian consumers from the impact of increasing international oil and gas prices.

During this period, all three of Canada's western oil and gas producing provinces created opportunities for participation in the upstream activities of the oil and gas Industry. Amongst these companies, Alberta Energy Company would be a mixed enterprise (50% by province and 50% private investors). Other companies such as Saskoil and British Columbia Petroleum Corporation would be entirely Government owned. In 1975, the Government of Canada created a National Petroleum Company, called Petro-Canada. The company was given mandate to aggressively involve itself in oil and gas exploration and development. The Government of Canada also extended preferential treatment to Petro-Canada, in particular in the acquisition of production rights in offshore development. Later, the company was mandated to enter into the downstream space as well. However the federal policy initiatives were not well received in the producing provinces of western Canada and resulted in strained political relations.

In 1980, soon after the second world oil price shock, the Government of Canada introduced the National Energy Programme, which broadened federal intervention in the energy business and increased federal provincial differences over energy policy. Federal taxes on oil production revenues and export sales were introduced, domestic price controls were allowed to continue, and further restrictions on allowed export volumes were imposed as a part of the National Energy Programme. All these initiatives led to a crisis in federal- provincial relationships and resulted in shut in production capacity in Alberta. Negotiations continued for months and finally the federal Government agreed to enter into an agreement with producing provinces on oil and gas pricing matters.

Years later the Federal Government of Canada decided to progressively reduce the scope and importance of policy initiatives due to increasing North American natural gas reserves and world oil prices. This decision was welcomed by the oil and gas industry and provincial Governments in Canada.

Between 1973 and1984, oil production remained at around the 1972 level of 1.8 million b/d and export oil sales declined from 50% in 1972 to 20% in 1984. Similarly only a marginal increase in natural gas production was witnessed during the period, reaching 7.3 billion cubic feet per day (Bcfd) in 1984 from the level of 6.5 Bcfd in 1972 and export sales declined from about 40% to 28% during the period.

**Eliminating federal Government control and moving towards a free market system - 1985 onwards**

In 1985, the federal Government of Canada came up with major changes to policy in order to eliminate the Federal Government's interventionist thrust that had been introduced with the National Oil Policy and intensified with the National Energy Programme. The Government eliminated the targeted special taxes levied by the Federal Government on oil and gas industry activity and price controls over crude oil and natural gas. Preferential treatment extended to exploration and development activities in the areas under Federal jurisdiction were also ended with the aforementioned changes in the policy. Buyers and sellers henceforth were allowed to enter into agreements for both domestic and export sales. These initiatives led the oil and gas industry in Canada to operate under market forces. This new direction to the federal energy policy was well received by the Governments of western provinces and Canada's oil and gas industry.

Since then, there has been no major departure from a market reliant federal oil and gas policy in Canada; market forces still influence the oil and gas upstream operations in the country. The upstream activities of the provincially owned companies were turned over to the private sector.

The mandate of Petro Canada was modified to operate like a private sector company and later on the Federal Government decided to proceed with the gradual sale of Petro- Canada's assets through stock offerings in the company. The privatization process was completed in 2004.

During this period, the Canadian Oil and Gas Industry witnessed a sustained increase in Oil and Gas output including first offshore production and finding of new reserves. Canadian Oil production in 2012 totaled 4.2 b/d and natural gas production 13.7 Bcfd. Canada exported about 53% of crude oil and 62% of natural gas produced in the country during 2012[59].

**Regulatory structure[60]:**

Canada's constitution explicitly vests ownership rights to natural resources with provinces in which these resources are located. Therefore, Canadian petroleum regime is characterized by federal–state (province) involvement in decision making about the development of petroleum resources.

The following are the key Alberta regulatory bodies governing oil and gas exploration:-

The Alberta Department of Energy: The department of the provincial Crown is responsible for the administration of the provincial legislation governing the ownership of oil and gas;

- The Energy Resource Conservation Board (ERCB): Oversees the oil and gas industry in Alberta; acts as an independent quasi-judicial agency of the Alberta Crown; is responsible for regulating the development of oil and gas resources in a manner that is fair, responsible and in the public interest through the issuance of licences to drill wells; determines spacing units for mineral reservoirs; regulates production rates; determines and enforces safety procedures; and oversees certain environmental aspects of well-site operations;

- The Ministry of Environment and Sustainable Resource Development (ESRD): manages air and water resources and the reclamation and remediation of oil and gas facilities and regulates forest resources, biodiversity, land-use and the management of public land.

- The Alberta Surface Rights Board (SRB): An independent adjudicative tribunal established by the provincial Crown to manage conflicts over surface access rights when an owner of mineral rights is unable to negotiate land access required to exploit oil and gas

- The Alberta Utilities Commission (AUC): Serves a quasi-judicial function in managing contraventions, objections and complaints arising under certain utility-related legislation; and is responsible for regulating the routes, tolls and tariffs of natural gas transmission through pipelines and for approvals for construction of pipelines and distribution facilities.

The following are the key federal regulatory bodies governing oil and gas exploration in Canada:

- The National Energy Board (NEB): under the authority of the NEB Act, NEB regulates interprovincial and international trade and commerce, including the importation, exportation and transportation of natural resources.

- The Canadian Environmental Assessment Agency (CEA Agency): Provides environmental assessments in order to contribute to informed decision making in support of sustainable development.

- The Department of Fisheries and Oceans (DFO): under the authority of the Fisheries Act, DFO delivers programmes and services that support the sustainable use and development of Canada's waterways and

[59]Statistics, Canadian Association of Petroleum Producers
[60] The facts about Alberta's royalties, Government of Alberta

aquatic resources, including monitoring pollution in waterways and conducting environmental assessments.

**Licensing regime and commercial structure:**

Canada has a concessionary type of fiscal regime whereby private ownership of resources is permitted. Oil and gas in Canada typically belong to the province in which the resource is located. Rights to explore, develop or produce oil and gas in a province are obtained by acquiring a petroleum or natural gas lease or licence from the province or from another party that holds such a lease or licence. As is typical with most concessionary fiscal regimes, the initial owner of the resource (usually a Government) leases or licences the right to take petroleum or natural gas from the lands but retains a royalty interest in the production.

In Alberta, 81% of mineral rights, including oil and natural gas resources, are owned by Albertans through the provincial Government. The federal Government owns a total of 10.6% which is held in trust on behalf of First Nations. The remaining 8.4% are privately owned by corporations and individuals. Rights to oil and gas resources that are owned by individuals and corporations are called “freehold rights.”

The provincial Government grants the right to explore for and develop Albertans’ natural resources. In exchange, companies/ contractors pay royalties to the provincial Government as compensation for the sale of those resources in addition to taxes paid on profits earned and any Resource Rent tax to share upside between Government and operator. In the case of freehold rights, the provincial Government charges an annual tax for oil and natural gas production on those lands.

Responsibility of managing and administering the exploration and development of crude oil and natural gas on First Nation reserve lands responsible agency lies with Indian Oil & Gas Canada (IOGC). IOGC assists First Nations with all stages of resource management. A producer must obtain the necessary licences and permits from IOGC when exploring and developing resources on First Nation reserve land. Royalties are also unique and are negotiated between the lessee and the Native Bands on a well by well basis. Unlike the royalty regime owned by provinces, IOGC does not take oil in kind and all royalties are paid in cash.

Royalties are not levied in isolation of taxes. The combination of various types of royalties and taxes is known as the fiscal system, which in Alberta consists of Royalty system and income taxation. Typical structure is given in the table below.

**Royalty System**

- The bonus bid system is the public offering of petroleum and natural gas resources owned by Albertans. The mineral rights are issued through a competitive sealed-bid auction system and the rights are leased to the highest bidder. Licenses and leases issued carry an annual rental fee of Crown land covered by the agreement.

- Contractor bears all the risk attached to exploration and production
- Royalties are levied based on the value of production.

**Taxes**

- A freehold mineral tax is levied on the value of oil and natural gas production from non-Crown (freehold) mineral rights. The rates vary for natural gas and oil.
- Companies pay corporate income taxes to both the provincial and the federal Governments
- Local municipal taxes are charged where applicable

Typical rates of royalties and taxes are provided in the table below.

*Table L - 3: Canada Rates of Royalties and Taxes*

| | |
|---|---|
| Royalties | • Crown royalties applicable to crown lands 10% to 45%<br>• Freehold royalties vary from lease to lease |
| Income tax rate | • Federal corporate tax rate is 15% in 2013 for income subject to tax in a province<br>• Provincial corporate tax rates vary from 10% to 16% depending on the province |

*Source: PwC analysis*

The overall objective of the royalty system in Canada is to provide a fair return to the people in the respective provinces in their capacity as owners of the province's energy resources. The royalty system also considers the risks companies undertake, given the significant investments that are required to explore for and produce oil and natural gas.

## Major Players

In Canada, oil and gas assets are owned through various methods, structures, relationships and entities, the most common being Canadian branches of foreign corporations, limited liability corporations, unlimited liability companies, general partnerships, limited partnerships and joint ventures. The type of entity used to conduct business and own assets depends on a number of factors, such as the nature of the business, the significance of limited liability to the parties, and tax considerations. The corporation is by far the most common entity used to conduct business and own assets in Canada.[61]

Canadian Corporation: The Corporation has the advantage of having the capacity and rights of a natural person and is considered a distinct legal entity (with separate liability) from its shareholders. For both federal and provincial corporations: (i) Canadian shareholders are not required; (ii) at least 25 per cent of the directors must be Canadian residents; and (iii) Canadian income tax is imposed on the worldwide income of the corporation.

Joint Ventures: Canadian corporations frequently take advantage of the joint venture organisational structure to own and operate oil and gas assets. Joint ventures of varying styles are often the structure of choice when the cost and risk of the development of assets are too great to be ideally developed by a single corporation. A typical joint venture is created when two or more parties agree to jointly own and operate certain assets by sharing capital, materials, equipment, personnel and technical expertise.

Partnerships: In Canada, corporations can enter into partnerships. Typically, all partners in a general partnership are entitled to participate in ownership and management, and each assumes unlimited liability for the partnership's debts and liabilities. In a limited partnership, there is a separation between the partners who manage the business (who are subject to unlimited liability) and those who contribute only capital (who are liable only to the extent of their contributions to the partnership).

Canada has also witnessed the acquisition of Canadian resource companies by foreign Companies such as Exxon Mobil as well as state-owned enterprises such as China National Offshore Oil Corporation (CNOOC). The Canadian Government encourages foreign investment that contributes to economic growth and employment opportunities in Canada. However, foreign investments that exceed certain monetary thresholds are reviewed under the federal Investment Canada Act to ensure benefit to Canada. Investments by foreign state-owned enterprises are subject to separate federal Government guidelines designed to require such enterprises to satisfy criteria relating to governance, transparency and commercial orientation.
Although there are numerous oil companies operating in Canada, the majority of oil and gas production is handled by the 8 companies as listed in the table below.

[61] TORYS: Canada Oil &Gas- A comparative Guide to oil and gas operations in Canada

*Table L - 4: Canadian Oil Companies*

| | Name of the company | Category | Type | Oil production in 2013 ('000 bpd) | Proved reserve (Billion barrels) |
|---|---|---|---|---|---|
| 1 | Suncor | Canada based integrated Oil and Gas company [Petro- Canada completed merger with Suncor Energy in 2009] | Public | 562.4 | 7.2 |
| 2 | Canadian Natural Resources Limited | Canadian based independent crude oil and natural gas producing company | Public | 671.16 | 4.51 |
| 3 | Imperial Oil | Canadian petroleum Company | Public (about 69% stake owned by Exxon Mobil) | 295 | 2.153 |
| 4 | EnCana Corporation | North American Oil and Gas company | Public | 516.7 | 2.2 |
| 5 | Husky Energy | Canada based integrated Oil and Gas company | Public (70% owned by a Hong Kong billionaire)[62] | 312.0 | 2.915 |
| 6 | Cenovus Energy | Canadian oil company | Public | 258.8 | 1.9 |
| 7 | Talisman Energy | Canadian integrated Oil and Gas company | Public | 373 | 1 |
| 8 | Nexen | Canadian upstream Oil and gas Company | Private (wholly owned subsidiary of China National Offshore Oil Corporation) | 207 | 2.5 |

*Source: PwC research and analysis*

[62] Rebecca Penty (November 1, 2012). "Husky Profit Rises on Refining Margin as Production Falls". Bloomberg

# Benchmarking – Midstream and Downstream

## Turkey

### Crude Oil and Petroleum

Turkey's importance in world energy markets is growing, both as a regional energy transit hub and as a growing consumer. Turkey's energy demand has increased rapidly over the past few years and will likely continue to grow in the future. Over the past decade, Turkey's economy expanded, and its petroleum consumption has increased. With limited domestic reserves, Turkey imports nearly all of its oil supplies. As of January 1, 2014, the Oil & Gas Journal (OGJ) estimated Turkey's proved oil reserves at 295 million barrels, located mostly in the southeast region. Turkey's oil production peaked in 1991 at 85,000 barrels per day (bbl./d), but then it declined each year and bottomed out in 2004 at 43,000 bbl/d. Although Turkey's production of liquid fuels has increased slightly since 2004, it is far short of what the country consumes each year.

### Refinery[63]

60% of Turkish oil demand is imported as crude oil and refined internally. Turkey mainly imports from Iran and Russia for raw refinery materials. TUPRAŞ, the market leader in the refinery business currently has four different refineries in Izmit, Izmir, Kırikkale and Batman. The refineries in Izmit and Izmir are the largest according to generation capacity. A private investment, SOCAR Star Refinery currently under construction, will produce diesel, jet fuel, LPG and petroleum products. The refinery is expected to be commissioned in 2017. A sixth refinery, Doğu Akdeniz Petrochemicals and Refinery is currently under construction as well. The aggregated capacity utilization ratio of the refineries increased from 74.7% in 2011 to 77 % in 2012, which indicates the importance of refinery capacity in the coming years. The status of the refineries is provided in the table below:

*Table L - 5: Turkey Refineries*

| Refinery | City | Status | Processing Capacity (10^6 T/Year) | Storage Capacity<br><br>(cubic metres) |
|---|---|---|---|---|
| **Star Refinery(SOCAR)** | Izmir | Under Construction | N/A | N/A |
| **Doğu Akdeniz Petrochemicals and Refinery**<br><br>**(Calik Holding)** | Adana | Under Construction | N/A | N/A |
| **TUPRAS** | Batman | Active | 1.1 | 228000 |
| **TUPRAS** | Kirikale | Active | 5 | 1.23 million |
| **TUPRAS** | Izmir | Active | 11 | 1.92 million |
| **TUPRAS** | Kocaeli(Izmit) | Active | 11 | 2.19 million |

*Source: TUPRAS*

[63] US Energy Information Administration

## Turkish Petroleum Refineries Company (TUPRAS)

The Turkish Petroleum refineries Company (TUPRAS) is the largest industrial enterprise in Turkey. TUPRAS operates four oil refineries, with a total of 28.1 million tons annual crude oil processing capacity. In addition, a majority stake (79.98%) in shipping company DITAS and 40% share ownership of petrol retailer Opet, creates synergies and adds value to the operations.

Refining Capacity[64]

When it was founded, TUPRAS had a crude oil processing capacity of 17.2 million ton a year. With the completion of the last phase of the İzmir Refinery Debottlenecking Project in 1984, total capacity was increased slightly to 17.6 million tons/year. Investments since then, such as the completion of the Kirikkale Refinery (5.0 million tons/year) in 1986 and the commissioning of an expansion project at the Izmir Refinery in 1987.

TÜPRAŞ/s crude oil production capacity reached 27.6 million tons/year. The total capacity has now reached 28.1 million tons/year, with the total processing capacity of all refineries in Turkey amounting to 32.0 tons/year. TÜPRAŞ, on its own possesses some 87.8% of the country's total refinery capacity. The Company is also ideally positioned from the standpoints of infrastructure, location, and logistical support for the importation of crude oil, LPG, and other petroleum products.

In 2012 TUPRAS had 77% capacity utilization with Diesel and Gasoline the highest contributors. The breakdown was as follows:

*Table L - 6: TUPRAS Production 2012*

| TUPRAS 2012 PRODUCTION('000 Tons) | |
|---|---|
| **Type** | **Production** |
| **LPG** | 783 |
| **Gasoline and Naphta** | 4826 |
| **Jet Fuel and Kerosene** | 3329 |
| **Gasoil** | 388 |
| **Diesel** | 5173 |
| **Fuel Oil** | 3477 |
| **Bitumen** | 2810 |
| **Lubricating Oil** | 266 |
| **Other** | 815 |
| **Total** | **21867** |

*Source: TUPRAS*

### Privatization

On July 10, 1990, a decision was made to privatize TUPRAS hence its shares were transferred to the Privatization Authority which is under the office of the Prime Minister. An IPO was carried out in 1991 where Class A shares corresponding to 2.5% of TUPRAS's capital were offered to the public. By the end of 1999, approximately 3.58% of TUPRAS's shares were traded on the İstanbul Stock Exchange, with the remaining 96.46% being held by the Privatization Administration.

In April 2000, the Secondary Offering of TUPRAS shares was completed resulting in trading shares of 49% of its shares on the İstanbul and London Stock Exchanges. Subsequently on September 12, 2005 the Privatization

[64] TUPRAS website
http://www.tupras.com.tr/detailpage.en.php?lPageID=1831

administration sold a block of 51% of the company's, shares to Koç-Shell Joint Venture Group at a value of US$ 4.14 billion. Resolution No: 2005/1128 of the Supreme Court approved the results of the auction. Accordingly, a Share Purchase agreement was signed with Koç Holding on January 26, 2006, endorsing the actual transfer of the shares.

### Developments since Privatization of TUPRAS[65]

The privatization of TUPRAS has led to improved efficiency and service delivery. Some of the major developments attributable to the privatization include:

**a. Excellent infrastructure, strong logistic and top position in storage**

TUPRAS controls all of Turkey's refining capacity. In terms of geographical location, its refineries are deployed adjacent to consumption areas. TUPRAS owns 59% of the total petroleum products storage capacity in Turkey, comprising of 1.7 thousand tons of crude oil, 1.3 million tons of white product and 0.9 million tons of black product. Having such a privileged position, the obligation to reserve an amount of at least 90 days petroleum stock required by Turkey will transform into a significant working potential for TUPRAS.

Strengthening its superior position in the market with Opet, the company with the second highest capacity in terms of terminal and storage advantages, TUPRAS has reached coverage of the entire country, including the market east of the Black Sea and Mediterranean which are far from TUPRAS' own refineries. TUPRAS is now able to meet the needs of the end user throughout all of Turkey, thus reinforcing its dominance in the domestic market by exchanging products and locations with Opet and Aygaz. TUPRAS produces its own power which it utilities at its refineries. With a 40 MW cogeneration unit that went on line in 2006 at the İzmit Refinery, TUPRAS has increased its cost advantage while lowering operational risk even more.

**b. Strong financial structure**

The company is enjoying high level of liquidity and has invested prudently in technology. For example, in 2006, it took advantage of its strong liquidity position and was able to increase its domestic market share and provide sales flexibility for its customers, effectively blocking the import advantage of other companies and initiating new ventures to sell the goods sent on consignment. The company also continues to pay very high levels dividends.

**c. Transportation and distribution partnerships**

With crude oil and petroleum products tankers, as well as its expertise in petroleum transportation, DİTAŞ which is 71.98% owned by TUPRAS plays an important role in TUPRAS operations: In addition to this affiliation, which provides the logistics for TUPRAS, another affiliate, Opet Petrolcülük A.Ş. joined TUPRAS on December 27, 2006. By acquiring 40% of Opet Petrolcülük A.Ş. shares, TUPRAS is able to follow the requirements and demands of the market more closely and to provide a rapid response. Opet, which is the fastest growing Company in the industry, is considered a significant element of TUPRAS's vision for expanding its services. The vertical integration launched with Opet minimizes TUPRAS' long time risk while facilitating its potential as a global player in the international arena.

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[65] TUPRAS website
http://www.tupras.com.tr/detailpage.en.php?lDirectoryID=103

d. **A process adding value to the company and the industry**

July 10, 1990 was a turning point in the history of TUPRAS, (which had been for many years a state economic enterprise) when it was handed over to the Privatization Administration. The Initial Public Offering was carried out in 1991 within the framework of the privatization plan whereby Class A shares corresponding to 2.5% of TUPRAS ' equity were offered to the public. By the end of 1999, approximately 3.58% of TUPRAS shares were traded on the İstanbul Stock Exchange. In April 2000, the secondary offering of TUPRAS was completed and the ratio of Class A shares traded on the İstanbul and London Stock Exchanges to total equity reached 34.24%. TUPRAS shares totaling 14.76% were sold to international buyers on the ISE Wholesale Market on March 4, 2005. As a result, 49% of TUPRAS shares are now publicly traded.

During 2005, events that held vital importance for the future of TUPRAS took place. The auction on September 12, 2005 by the Privatization Administration for the block sale of 51% of state-owned TUPRAS's shares was granted to the Koç-Shell Joint Venture Group at a value of US$ 4.14 billion.

## Transit and Infrastructure- Oil

Turkey plays an increasingly important role in the transit of oil. It is strategically located at the crossroads between oil-rich Former Soviet Union and Middle East countries, and the European demand centres. In addition, it is home to one of the world's busiest chokepoints, the Turkish Straits, through which 3.0 million barrels per day flowed in 2013.

## Domestic Pipelines

Turkey has two domestic crude oil pipelines and two major international oil pipelines to meet demand in Turkey and to transport exports. Turkey is also home to one of the world's busiest chokepoints, the Turkish Straits, and has been seeking bypass alternatives to ease the congestions in the area

The domestic crude oil pipelines are both owned and operated by BOTAS. BOTAS petroleum Pipeline Company (BOTAS) is the state owned crude oil and natural gas pipeline and trading company. Although BOTAS retains a monopoly foothold on the crude oil pipeline, monopoly rights of BOTAS on natural gas import, distribution, sales and pricing that was granted by the Decree of Natural Gas Utilization No. 397 dated February 9, 1990, were abolished by the Natural Gas Market Law numbered 4646. Natural Gas Market Law covers import, transmission distribution, storage, marketing, trade and export of natural gas and the rights and obligations of all real and legal persons related to these activities.

The two crude oil pipelines owned and operated by BOTAS are:

- The **Ceyhan-Kirikkale Pipeline**: This is a 278-mile pipeline that delivers crude oil from Ceyhan to the Kirikkale refinery near Ankara and can transport approximately 100,000 bbl. /d of crude oil.

- The **Batman-Dortyol Pipeline** runs approximately 320 miles and transports the domestically-produced crude oil in the Batman area to the terminal in Dortyol on the Bay of Iskenderun near Ceyhan.

## International Transport

Turkey continues to play an increasingly important role in the transit of oil supplies from Russia, the Caspian region, and the Middle East to Europe, with the Turkish Government deriving significant revenues from the transit fees. Significant volumes of Russian and Caspian oil move by tanker via the Turkish Straits to Western markets. [66]Approximately 3.0 million bbl./d flowed through the Bosporus and the Dardanelles in 2013 (approximately 2.5 million bbl./d of crude oil and 0.5 million bbl./d of petroleum products).

Oil shipments through the Turkish Straits decreased from over 3.4 million bbl./d at their peak in 2004 to 2.6 million bbl./d in 2006 as Russia shifted crude oil exports toward the Baltic ports. Traffic through the Straits increased again as crude production and exports from Azerbaijan and Kazakhstan rose in recent years. These changes have necessitated the establishment of international transit lines enumerated below:

*Table L - 7: Turkey International Transit Lines*

| Pipeline | Description | Capacity |
|---|---|---|
| **Baku-Tbilisi-Ceyhan pipeline** | Turkey's longest pipeline at 1100 miles. The pipeline transports Azeri light crude (mainly from the Azeri-Chirag-Guneshli field) via Georgia to Turkey's Mediterranean port of Ceyhan for further export. Since 2008, Kazakh crude oil has also been shipped via the BTC. The crude is then shipped via tankers to European markets. The pipeline initially came into service in June 2006.<br><br>It is owned by a consortium of 11 players including BP, SOCAR, Chevron, Statoil, TPAO, Eni, Total, Itochu, Hess and ConocoPhillips. It is operated by BP (30.1%) | 1.2 million bbl./d |
| **Kirkuk-Ceyhan pipeline** | Turkey's largest oil pipeline (by capacity). It is approximately 600 miles long and consists of two lines. However, only one of the twin pipelines is operational, with a maximum operational capacity of 400,000 bbl./d, According to the office of the Special Inspector General for Iraq Reconstruction (SIGIR). In late 2012, Iraq and Turkey agreed to continue crude oil imports through this pipeline for another 15 years, although frequent attacks on the pipeline regularly result in operation disruptions. Actual flows averaged just over 300,000 bbl./d in 2012.<br><br>It is operated by Iraqi's oil Ministry's North Oil Company. | 1.65million bbl./d |

## Bypass Routes

To ease increasing oil traffic through the Turkish Straits and in an effort to anticipate needed increases in pipeline capacity for increasing volumes of Caspian oil, a number of Bosporus bypass options are under consideration in Bulgaria, Romania, Ukraine, and Turkey itself. The BTC Pipeline, which bypasses the Turkish Straits chokepoint, is the first of many planned or proposed bypass pipelines to be constructed. Bosporus bypass options outside of Turkey include the Odessa-Brody pipeline in Ukraine, which currently transports crude oil into Odessa (reverse mode). Others have not yet been constructed, but proposals include the Pan-European Oil Pipeline, the Bourgas, Bulgaria to Vlore, Albania, and the Bourgas to Alexandropoulos, Greece pipeline.

There were a number of bypass options proposed in Turkey over the past decade, including:

[66] US Energy Information Administration
http://www.eia.gov/countries/cab.cfm?fips=tu

- **Samsun-Ceyhan Pipeline** would transport oil from Turkey's Black Sea port of Samsun to Ceyhan on the Mediterranean coast. The project includes the construction of a 350-mile oil pipeline, a new terminal for receiving oil at Samsun, a terminal for exporting the oil, and a storage plant at Ceyhan. The oil pipeline would have a maximum initial transportation capacity of 1 million bbl./d, which can eventually be increased to 1.5 million bbl./d.

- **Kiyikoy-Ibrikbaba Pipeline** is a 1.2 million bbl./d pipeline that would run between Kiyikoy on the Black Sea and Ibrikbaba on the Aegean Sea near Greece. This pipeline was proposed more than six years ago, but very little progress has occurred.

- **Agva-Izmit Pipeline** would connect the Black Sea to the Tupras' (Turkish Petroleum Refineries Company) Izmit refinery.

- **Canal Istanbul** is a proposed 30-mile link between the Black Sea and the Sea of Marmara. The waterway would be located on the European side of the Bosporus and completed by 2023. However, given the size of the undertaking and the associated cost, this project is the least desirable and least feasible option, and likely will not be completed.

- **Kurdish Regional Government (KRG) Pipeline** would connect oil fields in the northeast, KRG-controlled portion of Iraq to Turkey via an independent pipeline from Taq to Fishkhabur. The KRG has already constructed the pipeline with a capacity of 300,000 bbl./d, but Iraq's Government has threatened litigation against Turkey for buying KRG oil without official approval.

### Natural Gas

Turkey imports nearly all of it natural gas supply, a large majority of which comes through pipeline imports from Russia. Turkey also imports gas via pipeline from Iran and Azerbaijan and LNG from Nigeria and Algeria. Natural gas consumption has increased rapidly over the past decade. Despite the temporary declines recorded in 2009, natural gas consumption reached a peak of more than 1.6 trillion cubic feet (Tcf) in 2012. Natural gas is mainly used for power generation and space heating in the residential and commercial sector, although consumption in the industrial sector is rapidly increasing. Consumption growth is expected to remain strong as rising electricity consumption and new power plants continue to spur demand. Turkey's natural gas demand is highly seasonal, with heating season months (November through February) exhibiting natural gas demand that is significantly higher than in other months.

Turkey has begun to stake out its position as an energy bridge for gas supplies from the Caspian to Europe. However, in the long run, Turkey's need to satisfy rapidly growing domestic consumption could affect the country's position as a gas transit state.

### Pipeline imports

The majority of Russian gas arrives in Turkey via the Blue Stream pipeline, although sizeable volumes also reach the large population centers in and around Istanbul via the Bulgaria-Turkey pipeline. In total, Turkey imported approximately 0.9 Tcf of natural gas from Russia in 2012, according to Gazprom and Eastern Bloc Research. Turkey received about 290 Bcf of Iranian natural gas in 2012 via the Tabriz-Dogubayazit pipeline. An additional 118 Bcf arrived from Azerbaijan via the Baku-Tbilisi-Erzurum (BTE) pipeline in 2012. The Turkish central pipeline network distributed almost all of this natural gas to various consumers within the country. For Turkey to function as a gas transit state, it must be able to import enough gas to satisfy both domestic demand as well as provide enough pipeline capacity to transport Caspian natural gas across Turkey to Europe. While Turkey enjoyed considerable excess import capacity a few years ago, this excess pipeline capacity has eroded with rising domestic demand. This has been a major hurdle for players looking to supply Caspian gas to Europe via Turkey.

Additionally, the natural gas import infrastructure in Turkey has been a frequent target of terrorists, and Turkey is extremely vulnerable to supply disruptions. The Tabriz- Dogubayazit pipeline has been increasingly targeted by the Kurdish rebel militants. Flows on the Tabriz-Dogubayazit pipeline were disrupted a number of times in 2012. The Baku- Tbilisi-Erzurum pipeline has also been a terrorist target, and flows on this pipeline were halted twice in 2012.

Both the Turkish Government and private sector companies have proposed a number of pipeline projects with Turkey playing a vital role in natural gas transit. All are still in relatively early planning stages and in competition with each other - hence not all may be realized. In fact, in mid-2013, after over ten years in planning, sponsors of the Nabucco pipeline aborted the project, despite it having strong backing from the European Commission.

Proposed competing transit pipelines include:

- **South East European Pipeline (SEEP)**[67] was proposed by BP, although details on the proposal are scarce. SEEP would require the construction of only 800 miles of pipeline as it would rely on existing infrastructure and may exceed Nabucco's planned capacity. The pipeline was proposed by BP on 24 September 2011 as an alternative to the existing Southern Gas Corridor projects, including the Nabucco pipeline, Trans Adriatic Pipeline, and Interconnector Turkey–Greece–Italy. The pipeline was to use existing pipelines, but also needed 800–1,000 kilometres of new pipeline to be laid in different countries. The total route is about 3,800 kilometres .On 28 June 2012 the BP-led Shah Deniz consortium announced it will choose between Nabucco West and Trans Adriatic Pipeline as an export option, and accordingly development of the South East Europe Pipeline project will cease.

- **Trans Anatolian Pipeline (TANAP)** considered two alternatives, which included the possibility of upgrading the current BOTAÅ pipeline network and/or constructing a new standalone pipeline across Turkey to transport Azerbaijan's natural gas from the Shah Deniz II field. The pipeline's capacity would initially be 16 billion cubic meters steadily rising to 30 Bcm over eight years (1060 Bcf) per year. In early 2014, Turkey and Bulgaria agreed to build a new pipeline to connect the two countries' natural gas distribution networks, which would allow additional volumes from Shah Deniz to Europe. In May 2014 TANAP awarded Worley Parsons a significant five year contract for the supply of Engineering, Procurement and Construction Management (EPCM) services for the 1,841km Trans Anatolian Natural Gas Pipeline Project which has an estimated total project cost of USD 11.7 billion. SOCAR (80%), BOTAŞ (15%), and TPAO (5%) are the founding members of the consortium. SOCAR has the right to sell a part of its shares to minority partners. BP has agreed to acquire 12% stake in this project. The TANAP project company will be headquartered in the Netherland

- **Interconnector Turkey-Greece-Italy Pipeline (ITGI)** currently operates between Turkey and Greece. An expanded Greece-Italy section would transport about 350 Bcf per year of natural gas. ITGI is the new European gas infrastructure which will enable to open the so called 'Southern Gas Corridor' by connecting the Caspian and Middle East areas, where 20% of world's gas reserves are located, to Italy and Europe through Turkey and Greece. ITGI project also includes a pipeline between Greece and Bulgaria through IGB (Interconnector Greece-Bulgaria) with a transport capacity of 3 to 5 billion cubic metres per year. The pipeline will connect Komotini in Greece to Stara Zagora in Bulgaria and will be about 170 kilometres long. It will be developed by an Asset Company equally owned by IGI Poseidon SA and Bulgarian Energy Holding

Other proposed import pipelines include:

- **Turkey-Iraq Pipeline** would give Turkey access to Iraq's natural gas resources. Although a memorandum of understanding was signed a number of years ago, planning for construction has yet to

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[67] Soltanov E. The South East Europe Pipeline: Greater Benefit for a Greater Number of Actors(2012) http://www.iai.it/pdf/dociai/iaiwp1202.pdf

take place.

- **Extension of the Arab gas pipeline** to Turkey would allow delivery from Egypt to Turkey via Jordan and Syria. Given the political instability and unrest that have engulfed the region since 2011, this project effectively has been cancelled.

### Liquefied natural gas

Turkey imports LNG through long term contract supply from Algeria and Nigeria, with spot supplies from other suppliers including Qatar, Egypt, and Norway. LNG volumes arrive at the country's two terminals, Marmara Ereglisi in Tekirdag and the Aliaga terminal in Izmir.

**Marmara Ereglisi** has been in operation since 1994 and is owned by BOTAS. Its annual capacity is 8.2 billion cubic meters (bcm), or 290 Bcf, and has a maximum send out capacity of 22 million cubic meters (mcm) per day.

The **Aliaga terminal** is owned by EGEGAZ, with an annual capacity of 6 bcm. Its maximum send out capacity is 16 mcm per day.

### Regulatory Structure

#### Major Regulatory Bodies

Petroleum activities in Turkey are regulated by three Governmental authorities namely the Ministry of Energy and Natural Resources (MENR), the General Directorate of Petroleum Affairs (GDPA) and the Energy Market Regulatory Authority (EMRA).

MENR is responsible for preparing and implementing high-level energy policies, strategies and plans in co-ordination with its affiliated institutions, and other public and private entities.

EMRA was established on 19th November 2001 by the Law numbered 4646 in Turkey. It regulates all energy markets which are electricity, natural gas, oil and LPG markets. The fundamental objective of EMRA is set forth in its founding documents as to ensure the development of financially sound and transparent energy markets operating in a competitive environment and the delivery of sufficient, good quality, low cost and environment-friendly energy to consumers and to ensure the autonomous regulation and supervision of these markets. It doesn’t have direct control of any public authorities as it has to be fully independent in terms of political effects.

Other bodies include the Turkish Competition Authority and the Competition Regulatory Board.

#### Liberalization of market

In September 2012, MENR proposed a new gas sector liberalization bill. The new version of the bill calls for BOTAŞ to be unbundled into three distinct entities: an LNG trading group, a gas transmission system operator, and a storage facility operator. Gas import and export rights would be transferred to private companies under this new bill. The Prime Minister will need to approve the bill and introduce it to Turkish Council of Ministers before it becomes law.

According to a Decree of Council of Ministers dated August 15, 1974 and numbered 7/7871 Oil Carriage by Pipelines Joint Stock Company ("BOTAŞ") has been established to manage and operate the oil pipelines.

#### Role of BOTAS in natural gas market

BOTAŞ’s monopoly rights on natural gas import, distribution, sales and pricing that were granted by the Decree of Natural Gas Utilization No. 397 dated February 9, 1990, were abolished by the Natural Gas Market Law. The

Law covers import, transmission distribution, storage, marketing, trade and export of natural gas and the rights and obligations of all real and legal persons related to these activities. BOTAŞ undertakes on its activities as a major market player pursuant to the Natural Gas Market Law No. 4646.

**Licensing and Tariffs**

Licenses are granted in return of a cash deposits. The tariffs applied by EMRA as of 2013 were:

- License fee for oil refiner operators is 415.000-TL (approx. € 151,000),
- License fee for carriage of oil through maritime transport is 3.000-TL for each vessel (approx. € 1,200).

Transportation process in this sector is strictly regulated due to security reasons and to prevent any black market activity. Furthermore, there is an improved operating network of gas and oil pipelines in Turkey. In this respect, it should be noted that the construction of pipelines is subject to many different regulations and different procedures shall apply depending on the location. In addition, construct pipeline or storage facilities require specific licenses to be obtained from Energy Market Regulatory Authority and BOTAŞ. Furthermore, an application and a consent requisition shall be filed before the relevant municipality and/or other concerned directorates (e.g. Directorate for Motorways).

Licenses are granted for a maximum period of 49 years. This period can be subject to renewals and extensions based on the requisition of the licensee. It should be noted that such extension request shall be filed before the Energy Market Regulatory Authority at least two (2) months prior to expiry.

**Pricing**

Sell & purchase prices in oil market shall be formed and determined based on the nearest accessible global free market conditions in accordance with the Petroleum Market Law numbered 5015. As per the domestic crude oil, prices shall be formed based on the "market Price" at the nearest port of delivery or refinery. However, according to the Natural Gas Market Law numbered 4646 prices vary based on connection price, transmission storage price, wholesale price, retail price.

The Energy Board has the right and authority to intervene in pricing if infringement of Competition Law no. 4054 with regards to pricing is determined.

**Competition**

When it comes to competition in the oil market, the general conditions concerning competition is stipulated in the Act on the Protection of Competition in Turkey. This Law applies within the oil market as well. The Competition Regulatory Board has an authority to intervene the market structure in the oil market as well. Three important situations are controlled by Competition Regulatory Board; first, agreements which considerably prevent, restrict and distort competition, second abuse of dominant position, and lastly, mergers and accusations.

Referring to the competition in the oil market, there are two crucial authorities which are Energy Market Regulatory Board and Competition Regularity Board. In comparison with the Competition Board, the Energy Board has a limited authority concerning providing competition in oil market.

In addition to new technologies for exploration and production, the sector is impacted by broader technological advancements. Competition Law and Turkish Competition Authority regulate such matters. However, except of the general provisions set forth by the Competition Law and Turkish Competition Authority for the whole markets, there isn't any specific provision for oil market. On the other hand, as per the gas market, certain special exemptions are set forth within Article 7a of Natural Gas Market Law numbered 4646. In this respect, foreign companies selling gas to Turkish market are restricted to sell more than the 20% of the total yearly consumption provision indicated by the Energy Market Regulatory Authority. Furthermore, legal entities operating in the gas market are also restricted from incorporating other companies.

**Security of Supply**

Security of supply becomes a significant issue as dependence on foreign sources in Turkey is too high. Also, it is important for the national security reasons. Therefore, 90 days of oil stock requirement is stipulated in Article 16 of the Oil Market Law. The main reason of this regulation is:

I. To provide sustainability in the market and prevention of crisis;

II. To comply with EU oil stock Regulation

III. To fulfil requirements of International Energy Program Agreement, and

IV. To protect the market after the liberalization and privatization process.

The second important issue that assures security of supply is the national marker application. National marker is a sign that ensures to identify the products put on the market legally within the country. National marker indicates that the product is legally produced or imported in Turkey, and it is defined by EMRA according to National Marker Implementation on Oil Market Regulation. As it is commonly known, the oil products directly enter into the market from refineries or indirectly from customs. In both cases, the product put on the market is significantly important in terms of quality, security and tax evasion.

Refineries and fuel distribution licensees are obliged to hold at least 20 days of product stocks based on the average daily sales of previous year. These stocks must be held at their own storage or licensed storage facilities. New entrants in the distribution market are obliged to hold 3.3 Kt of stocks at minimum.

While the NOSC determines the base number of days, the type, quantity and place of emergency oil stocks, the EMRA is given the legal authority to conduct regular inspections and to order a company to provide any information necessary for its stockholding obligations.

### Summary of Observations

Turkey is a crucial learning point on successful privatization. The privatization process is driven by the need for change and receives massive support from both the Government and private sector. There is involvement from all stakeholders in this process. The process should be transparent and must be driven by a clear need for value addition.

Turkey has developed its oil and gas infrastructure through various partnerships. These range from intra-country partnerships and inter-country partnerships. The pipeline system has greatly grown due to partnerships between various firms involved in the industry. Some of the developments are made across countries to enhance synergies. Some of the partnerships are between Governments highlighting the need for positive regional integration policies

## Canada

### Overview of Downstream Petroleum Sector

The downstream segment is an integral component of Canada's oil and gas value chain. This segment consists of refineries that process crude oil into the marketable product and LNG terminals that convert liquefied natural gas into marketable state are also a component of downstream sector in Canada. The downstream sector also comprises of petroleum product distributors and natural gas utility companies that market and sell refined oil and gas to retail customers.

### Two tier regulatory structure

In Canada, the participants in the oil and gas industry are often subject to both federal and provincial regulators since these levels of Government have overlapping or shared legislative authority in the areas of natural resource development, transportation, marketing and the environment. In this section, the major regulatory bodies in the Canadian Federal Government and the Alberta Provincial Government along with their responsibilities have been discussed.

Although the fundamental legal concepts and provincial legislation for oil and gas operations in these provinces are substantially similar, there are certain differences that have been considered while discussing the regulations in different provinces, for example price regulation.

The following are the key federal regulatory bodies governing the oil and gas downstream activities in Canada:-

- **National Energy Board (NEB): NEB** is an independent federal agency established in 1959 by the Canadian Parliament to regulate international and interprovincial aspects of the oil, gas and utility industries. The purpose of the NEB is to regulate pipelines, energy development and trade in the Canadian public interest. NEB is also the authority that approves LNG licence applications in Canada.

- **Canadian Environmental Assessment Agency (CEA Agency)**: Provides environmental assessments in order to contribute to informed decision making in support of sustainable development.

The following are the key Alberta regulatory bodies governing oil and gas downstream operations:-

- **Alberta Department of Energy**: The department of the provincial Crown is responsible for managing the development of province's oil and gas resources, granting industry the right to develop oil and gas projects etc.
- **Energy Resource Conservation Board (ERCB):** Oversees the oil and gas industry in Alberta and acts as an independent quasi-judicial agency of the Alberta Provincial Government. Businesses that have a proposed project in Alberta's energy industry must make an application to the ERCB for necessary approvals. Large developments such as refining projects fall under the Alberta Environmental Protection and Enhancement Act, and the Water Act may require an Environmental Impact Assessment to be done as a part of getting the business approval from the ERCB.
- **Ministry of Environment and Sustainable Resource Development (ESRD):** Manages air and water resources and the reclamation and remediation of oil and gas facilities and also regulates forest resources, biodiversity, land-use and the management of public land.
- **Alberta Utilities Commission (AUC):** Serves a quasi-judicial function in managing contraventions, objections and complaints arising under certain utility-related legislation; and is responsible for regulating the routes, tolls and tariffs of natural gas transmission through pipelines and for approvals for construction of pipelines and distribution facilities. The AUC regulates investor-owned natural gas utilities to ensure that customers receive safe and reliable service at reasonable rates. The AUC also provides regulatory oversight of issues related to the development and operation of the retail gas markets in the province.
- **Petroleum Tank Management Association of Alberta (PTMAA):** PTMAA's responsibility is to

promote the safe management of petroleum storage tanks in Alberta and enhance the protection of human life, health and the environment. The Association has an Administration Agreement with the Minister of Alberta Municipal Affairs.

## Regulatory approvals required for setting up projects in downstream value chain

### Refining

Governments of respective provinces have the authority to issue necessary approvals for oil and gas downstream projects in Canada. For example in Alberta, the Energy Resource Conservation Board (ERCB) gives approval for proposed refining projects in Alberta. Refining projects may require an Environmental Impact Assessment under Alberta's Environmental Protection and Enhancement Act in order to obtain approval from ERCB.

### Storage and Distribution

**Petroleum products:** Regulations pertaining to the installation and registration of aboveground storage tanks (ASTs) are documented within the Alberta Fire Code (AFC). Every storage tank installation requires pre-approval from the Petroleum Tank Management Association of Alberta. The PTMAA provides storage tank installation advice to all stakeholders, regardless of the location of the planned installation. The regulation mandates that a permit shall be applied for and issued for all petroleum storage tank installations, removals, or alterations.

**Gas:** Approval on the distribution rates for investor-owned distribution systems is obtained from the Alberta Utilities Commission (AUC). Distribution charges for other distributors are set by the applicable regulator - by municipal councils with respect to some municipally owned utilities and by the elected board members of natural gas co-operatives.

### Marketing

**Petroleum products:** The marketing and retailing of gasoline is carried out by many firms, which can generally be divided into two types. The first type consists of outlets operated by the integrated refiner marketers who produce the gasoline, distribute it and market it, often through affiliate or licensed operators who own individual outlets. Licenses can be obtained from the municipal Government. These companies provide gasoline to their own network and to other retailers under contract.

The second type consists of the independent marketers. Independent marketers are those who do not own a refinery but either buy their product from Canadian refiners or import the gasoline. They tend to operate small numbers of outlets in specific locales, but some large networks exist. Generally, the large independents have a 15-25% share of the sales volume in urban markets.

Municipal Government is the authority which issues its own business licenses within its jurisdiction.

**Gas:** All businesses marketing natural gas contracts in Alberta are licensed by the province and abide by a strict code of conduct, which requires that the company must make timely, accurate and truthful comparisons; all advertising materials must reflect actual conditions; all data used to support a claim must be reliable, and; salespeople must identify themselves properly and show identification cards when requested. All retailers of natural gas, regardless of the rate or contract, will provide an energy charge for the measured amount of gas consumed, and a delivery charge, which is an infrastructure charge to deliver the energy.

Natural gas retailers purchase natural gas from the producers and then sell the natural gas they have purchased to consumers, either at the regulated rate or under contracted terms. Consumers that have not signed a competitive contract will automatically receive service from the regulated rate provider that is available in their area. The regulated rate is regulated by the AUC, however the AUC has no jurisdiction over competitive retailers.

## Import and Export

**Petroleum product:** The NEB authorizes oil exports by issuing short-term orders for periods less than one year for light crude oil and less than two years for heavy crude oil. These exports occur under short-term orders due to characteristics of the oil market. The Board does not regulate oil imports. Canada produces enough oil to meet its own needs and has been a net exporter of oil for some time; however, oil is imported to supply both the Atlantic Provinces and Quebec.

The NEB monitors the supply and demand of oil, as it does with natural gas, to ensure quantities exported do not exceed the surplus remaining after Canadian requirements have been met.

**Natural gas:** The export (liquefied natural gas export) and import of natural gas is authorized by NEB under either long-term licenses or short-term orders. Following a public hearing, long-term licences may be issued for up to 25 years subject to Governor in Council approval. Short-term orders for a maximum period of two years can be issued without a public hearing and do not require Governor in Council approval.

The Board monitors the supply and demand of natural gas, including the performance under existing export authorizations. This ensures that the quantity of gas exported does not exceed the surplus remaining after Canadian requirements have been met.

## Competitive Industry Structure

Market-based Pricing of Petroleum products practiced at large with jurisdiction of provinces to exercise controls over prices.

Canada today adopts a market-based approach to determine prices for petroleum products. With the exception of a national emergency, the Government of Canada has no jurisdiction over the direct regulation of retail fuel prices. Under the Canadian Constitution, the provinces have the authority to control prices of petroleum products. Some provinces choose not to exercise their regulatory authority, relying instead on market forces.

Alberta follows a market based approach in determining fuel prices. The Government of Alberta supports the competitive market place system (supply and demand) and is not considering the regulation of retail prices of petroleum products. Gasoline prices are determined in the competitive Market place by the forces of supply and demand, which vary between regions, cities and neighborhoods. The final retail price includes the cost of crude oil and the costs to refine, transport, distribute and market gasoline in Alberta. Federal and provincial taxes are also included in the final price you pay for gasoline.

Others, including Prince Edward Island, Newfoundland and Labrador, Nova Scotia, New Brunswick and Quebec, regulate prices in some way. For example in New Brunswick, the New Brunswick Energy and Utilities Board sets maximum prices for petroleum products sold. The procedure for price calculation is described below.

- Step 1: Benchmark price is estimated on the average prices in the international markets where the product is sold in significant volumes (motor fuels and furnace oil the benchmark is based on the average New York Harbour Cargo Price). The Board calculates weekly benchmark prices based on the average of the daily product prices for each week.
- Step 2: The wholesale margin is added to the benchmark price to estimate the wholesale price.
- Step 3: After the wholesale margin is added, the appropriate taxes are applied. In the case of motor fuels, Federal Excise Tax, Provincial Motor Fuels tax etc. are all applied.
- Step 4: Setting the Retail Price: The retailer is allowed to add 5.9 cents per litre to the wholesale price. In the case of full-service gasoline retail, the retailer may also charge an additional 2.5 cents per litre.
- Step 5: Adding the Delivery Charge: The wholesaler may add a delivery charge to cover the cost of delivering petroleum to various parts of the province.

**Pricing of Natural Gas**

Natural gas prices are set in an open and competitive market and are influenced by many variables throughout North America. These variables include supply and demand, production and exploration levels, storage injections and withdrawals, weather patterns, pricing and availability of competing energy sources and market participants' views of future trends in any of these or other variables. The NYMEX natural gas futures contract is widely used as an international benchmark price, including in Alberta.

Regulated monthly natural gas rates in Alberta are based on expected natural gas prices for the month and any balances or credits carried forward from prior months. There are two major companies responsible for providing regulated natural gas service in Alberta: Direct Energy Regulated Services (providing gas for customers of ATCO Gas North and South) and AltaGas Utilities. Their natural gas rates are set at the beginning of each month, subject to verification by the Alberta Utilities Commission. These rates reflect the forecast market price for the upcoming month, correcting for any amount that is over- or under- collected from previous months i.e. the regulated monthly natural gas rates are based on expected natural gas prices for the month and any balances or credits carried forward from prior months.

Over and above the wholesale natural gas price mentioned above, the retail gas price includes a distribution charge, or a charge to cover the fixed costs of infrastructure to deliver the natural gas to the consumer, as well as other charges, such as General Sales Tax (GST) and administration charges.

**Private companies operating the pipelines under regulated environment**

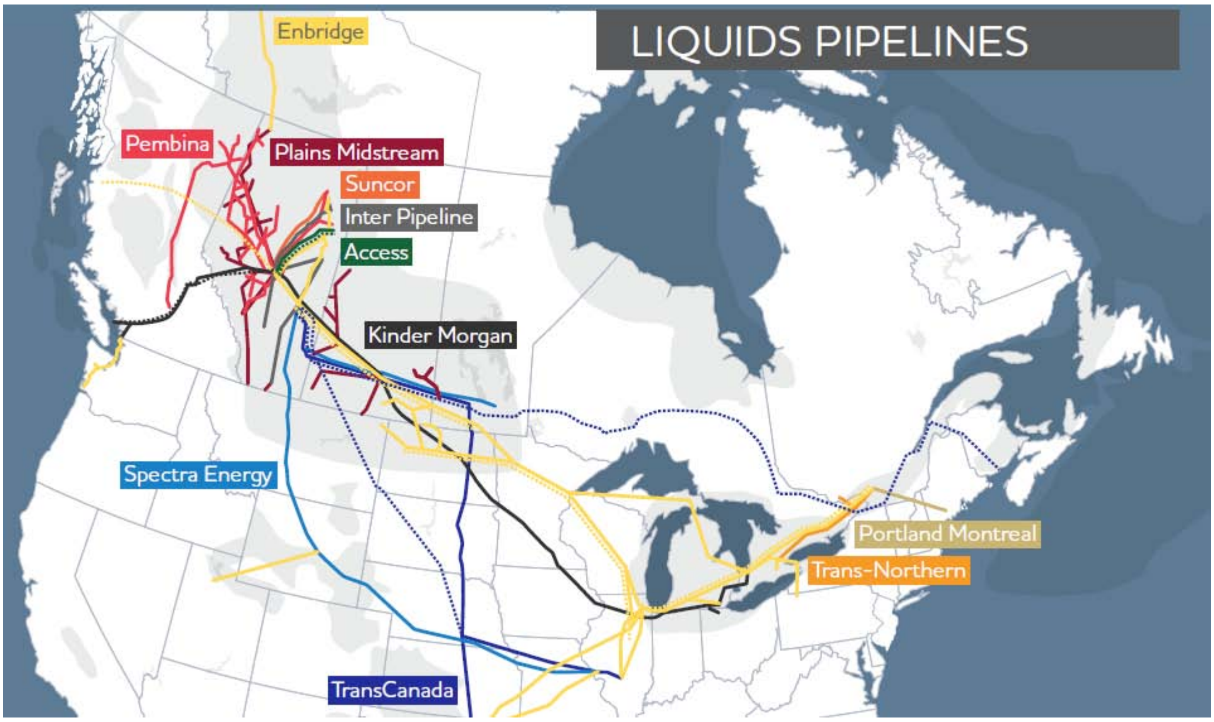
Canada has a proud history of pipeline construction and operation dating back to 1853 when a 25 kilometre cast-iron pipe moving natural gas to Trois Rivières, QC was completed and by 1947, three Canadian crude oil pipelines existed. Canada's extensive pipeline grid began in the 1950s when major crude oil and natural gas finds in Western Canada led to the construction of large pipeline systems.

Currently there is an estimated 825,000 kilometres of pipeline transmission and distribution lines in Canada, with most provinces having significant pipeline infrastructure. This includes 105,000 kilometres of large diameter transmission lines. Out of this, approximately 71,000 kilometres are federally-regulated pipelines, which are primarily transmission lines. Pipelines operate in both remote and populated areas.

In Canada, private companies own and operate pipelines. However these Pipelines are regulated based on jurisdiction, according to Canada's Constitution. The National Energy Board (NEB) regulates pipelines that cross inter-provincial or international boundaries. This includes nearly 71,000 kilometres of inter-provincial and international pipelines within Canada. The NEB regulates approximately 100 pipeline companies in Canada. Pipelines that are intra-provincial are regulated by each individual province. For example, in Alberta, these pipelines are regulated by the Alberta Energy Regulator. In British Columbia, such pipelines are regulated by the British Columbia Oil and Gas Commission. This includes the smaller natural gas distribution lines which go to every house with a natural gas furnace or water heater. Alberta, for example, regulates close to 400,000 kilometres of pipelines. Regulators are also involved in establishing pipeline tolls and tariffs. Tolls are the rates changed by pipeline companies for transporting product through their lines. The toll, along with the other terms and conditions under which the service of a pipeline company are offered comprise the tariff.

The decision to build pipeline is made by commercial participants based on market demand for transportation capacity. Pipeline companies propose projects based on their predicted economic feasibility. Before any project for an international or inter-provincial pipeline can proceed it must be reviewed by the NEB to ensure that it is designed, constructed and operated in a manner that promotes safety and security, environmental protection and efficient energy infrastructure and is in the Canadian public interest.

*Figure L - 2: Map of Canadian Liquidis Pipelines*




*Source: Canadian energy pipeline association, Natural Resource Canada, Government of Canada*

**Compulsory stock policy**

Canada is an IEA member country. As per the International Energy Programme agreement, each IEA member country has an obligation to have oil stock levels that equate to no less than 90 days of net imports. Since Canada is a net exporting country, they do not have a stockholding obligation under the I.E.P. Agreement. [68]

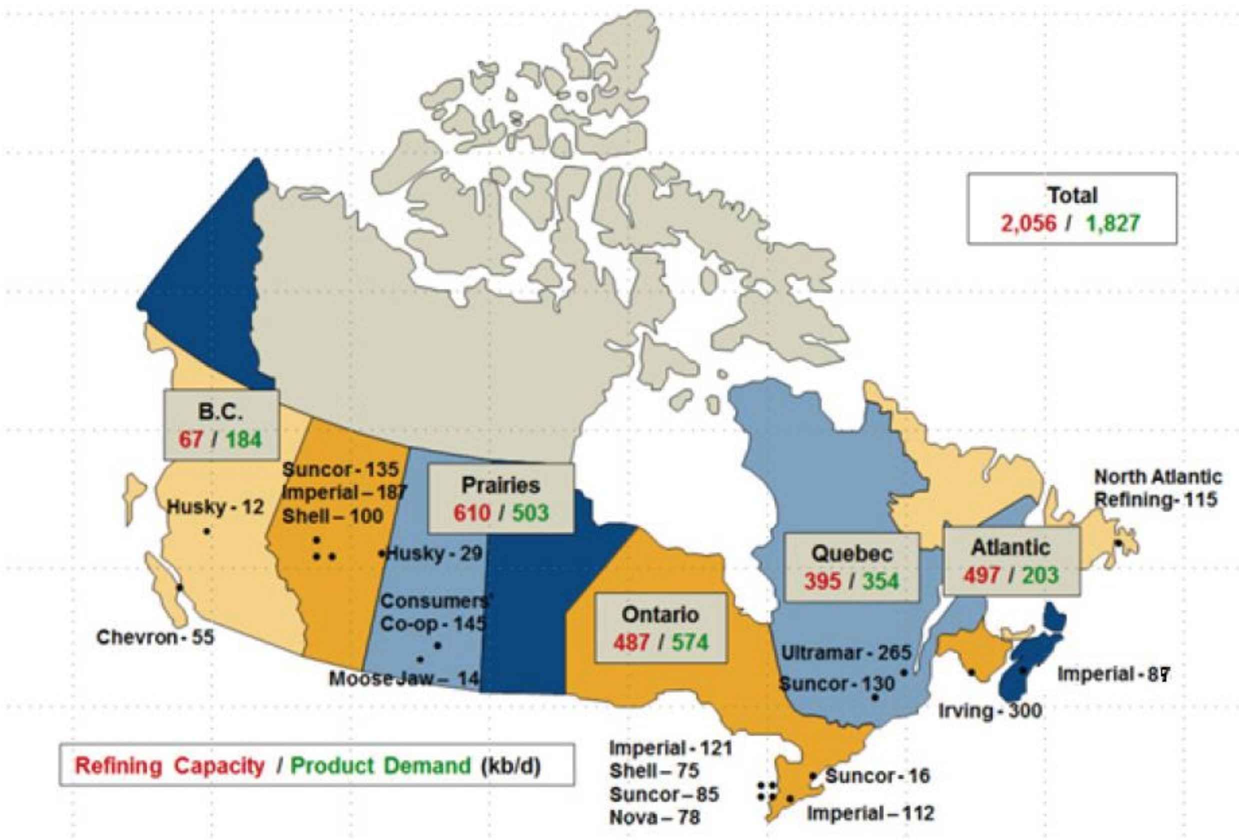
**Competitive Industry structure**

Canada has 19 refineries located in eight provinces with a total capacity to refine about 2 million barrels of oil per day. Canadian refineries are primarily located in three centres: Sarnia, Ontario, Quebec, Edmonton and Alberta. Canadian refineries are small by international standards.

Because of the historic abundance of domestically produced light sweet crude oil and the strong demand for distillate products, most of Canada's refineries are cracking refineries. Heavier oil sands production in the country has resulted in a shift towards addition of more coking capacities in Canada. Integrated oil companies are present in petroleum downstream business—from exploration and production through to refining and distribution of their products in retail stores across Canada. These represent some of the largest companies in Canada, including Imperial Oil, Suncor, Husky Energy, and Shell. However, integrated oil companies are joined by more regional ones—such as Irving Oil, Ultramar, Chevron, and North Atlantic Refining—to form the bulk of the transportation fuel manufacturing industry in Canada. Industry rationalization, beginning in the early 1970s, cut the number of refineries in Canada from nearly 40 to just 19 today. However, the reduction in numbers was offset by an increase in capacity at the remaining facilities. These capacity increases were achieved through significant capital investments that contributed to the growth in the efficiency of the sector. And because of these investments, total refining capacity has not changed dramatically over time, even though the number of operating refineries is much less today than in the 1970s.[69]

[68] International Energy Agency

[69] Canada's Petroleum Refining sector: An Important Contributor Facing Global Challenges, Conference Board of Canada, 2011




*Source: Committee report, Parliament of Canada, 2013.*

The marketing and retailing of gasoline is carried out by many firms, which can generally be divided into two types. The first type consists of outlets operated by the integrated refiner marketers who produce the gasoline, distribute it and market it, often through affiliate or licensed operators who own individual outlets. These companies provide gasoline to their own network and to other retailers under contract. The second type consists of the independent marketers. Independent marketers are those who do not own a refinery but either buy their product from Canadian refiners or import the gasoline. They tend to operate small numbers of outlets in specific locales, but some large networks exist. Some of the larger networks of independent stations include Couche-Tard, Canadian Tire etc.

The three major refiners - Imperial Oil, Shell and PetroCanada - account for about 36% of the branded stations in Canada and have the largest share of stations in each of the regions except the Atlantic. Imperial Oil is the largest retailer in Canada with 1,978 Esso stations followed by Shell's 1,762 and PetroCanada's 1,375 sites. It is important to note that a large percentage of these "branded" stations are independently owned and operated under supply contracts with the company whose brand of gasoline is sold at that outlet.

There is also an important distinction between the number of outlets a company owns and their market share. Not all stations have the same volume throughput. The majors tend to have higher volume throughput per outlet so generally are able to capture a larger share of the market with fewer stations.

### Health Safety and Environment guidelines:

Downstream oil and gas sector activities fall under the purview of the Alberta Environmental Protection and Enhancement Act and the Water Act. Large projects in oil and gas downstream require an environmental impact assessment to be done as a part of getting the business approval from ERCB. In addition the key regulations pertaining to environmental aspects of oil and gas activities in Canada include the following:

**Water Act and The Water for Life strategy in Alberta:** The Water Act, R.S.A. 2000, supports and promotes the conservation and management of water, including the wise allocation and use of water, while recognizing the need for economic growth and prosperity. The Water Act requires that an approval for issuing water license under the Environmental Protection and Enhancement Act must be obtained for any activity, diversion of water or operation of a works. Small volume use and some private or municipal use of water are exempt from this requirement.

All licenses require that records of water use be maintained. Most users are required to report their actual water use to Alberta Environment and Water. Alberta Environment and Water publishes the water use and discharge for various industries in their annual report. Some water licenses include provisions under the Water Act which references the "Water Management Framework for the Industrial Heartland and Capital Region" requiring that users adhere to sector-based water conservation targets.

The Water for Life strategy was introduced to support the stewardship of water in the province. The Alberta Government's Water for Life strategy (2003) has set a target for Albertans to achieve a 30 percent improvement in water-use efficiency and productivity. The Alberta Water Council (AWC) was established by the province to spearhead this goal. Under the auspices of the AWC, a Conservation Efficiency Productivity (CEP) Team recommended that seven major water-using sectors in the province prepare a CEP plan to guide their sector towards achieving the Water for Life goals. The Downstream Petroleum Sector CEP Plan covers refining, marketing and distribution operations in Alberta and provides details on the current state of water use and progress that has, and is being made, toward more efficient use of this resource. It also identifies potential opportunities to enhance CEP efforts. The sector focuses on specific measures to achieve further CEP gains and to define targets and mechanisms that will assist them in achieving the CEP gains targeted through AWC's response to Alberta's Water for Life strategy (2003).

In addition to the Water for Life strategy, there are other policies, programs and plans that apply to water management in Alberta that could affect the downstream petroleum sector.

**Water Management Framework:** Promoting water conservation for all users, greater use of reclaimed or recycled water Wetland Management in Settled Areas of Alberta: This policy could apply to refining/marketing operations if, and when, an application for new site construction and/or expansion of the existing facilities may impact wetlands.

**EMS/QMS Registration:** Since the end of 2005, three refineries in Edmonton have been registered under the ISO 14001, Environmental Management System. Under this Management System, refineries have undertaken various projects to continually reduce their reliance on water usage in the refineries. In addition, refineries are also registered under the ISO 9000 Quality Management System which provides an additional layer of compliance with codes, policies, standards and regulations.

**Refinery Projects Risk Assessment and Hazard Identification**: Hazard Assessment and Operability Procedure (HAZOP) is a fundamental step in any project implementation. Environmental risk assessment and mitigation plans are also a necessary step for proper project management and as a result are rigorously implemented in all petroleum refinery projects.

**Capital Improvement Plans**: In response to regulatory changes, the need for improving efficiency and/or reducing their environmental foot print, capital expenditures for environmental improvement are allocated each year CPPI (Canadian Petroleum Product Institute) members. Annual capital expenditures are reported in the CPPI member companies' individual annual reports.

### Fuel Quality Norms in Canada

Standards are developed by the Canadian General Standards Board (CGSB) and implemented by Environment Canada. Canada has legal requirements for the sulfur concentration in on-road, off-road, locomotive and marine diesel fuels that generally align with those of the US EPA. As per the current norm, the sulfur level in on-road and off-road diesel fuel should be less than 15 mg/kg (15 parts per million (ppm)).

Sulphur levels of gasoline have been regulated since 2002 and the regulation requires sulphur levels in Canadian gasoline to average no more than 30 parts per million (ppm) or 30 mg/kg with a maximum of 80 ppm. Similarly Benzene in gasoline has been regulated since 1999 and the regulations limited the sale of benzene to 1.5% by volume.

### Summary of Observations

Historically, to keep pace with developments in the upstream petroleum sector, refinery capacities were set up for monetising the increasing oil production through the manufacture of petroleum products. Further, driven by the natural resource developments, the refinery configuration underwent a change by way of technological up-gradation to utilize heavy oil sands. The refinery capacities were sufficient to meet the domestic demand of petroleum products thus creating a marketable surplus for exports. The developments in marketing infrastructure (storage and distribution infrastructure and retail outlets) were in tandem with developments on the refinery front. A significant departure, though from the past is the reducing dominance of the integrated oil refining and marketing companies and emergence of independent marketers. The evolution of the regulatory regime and transitioning towards a conducive and established regulatory regime has contributed to this development. The market is characterized by presence of a large number of suppliers and marketers. The barriers to entry are minimal with the licenses and permits granted by the regulatory bodies under the aegis of the Federal and Provincial Governments in accordance with the regulatory provisions. Although, the prices of petroleum products are left to be determined by the market forces of demand and supply, the Provincial Governments do have jurisdiction of exercising control over product prices.

# *Malaysia*

## Overview of Petroleum Sector

As highlighted earlier, Malaysia is the second largest oil and natural gas producer in Southeast Asia, the second largest exporter of liquefied natural gas globally, and is strategically located amid important routes for seaborne energy trade[1]. In recent years, crude oil production has witnessed a decline from 722,000 b/d in the year 2000 to 657,000 b/d by 2013. This is largely due to country's National Depletion Policy, established in 1980, which has kept hydrocarbons production at 3% of total reserves each year.

With an objective to increase production by 5% per year up to 2020 to meet domestic demand growth for petroleum products and to sustain crude oil and LNG exports to overseas markets, the Malaysian Government introduced new tax and investment incentives in 2010 to promote oil and natural gas upstream operations in the country.

Gas production began in the mid the 1980s and increased rapidly to 45 Bcm by the year 2000. It has continued to increase and in 2013 amounted to around 70 Bcm. Production is approximately evenly split between supply for the domestic market and for LNG exports. LNG export plants started up in 1996 (MLNG Dua 7.8mtpa), in 1983 (MLNG Satu 8.1mtpa) and in 2003 (MLNG Tiga 6.8mtpa). Despite being a major LNG exporter, Malaysia has recently turned to LNG imports, with the commissioning of its first LNG terminal in April 2013 with a capacity of 3.8 mtpa. Malaysia also imports small amounts of pipeline gas from Indonesia.

Today, oil and gas production contribute less than 10% to Malaysian GDP. It has a diversified economy, in which most of the GDP is provided by services and manufacturing, largely based on electronics.

## Regulatory structure

### The Ministry of International Trade and Industry and Ministry of Domestic trade, Co-operatives and consumerisms (MDTCC)

Downstream activities are regulated by two bodies under the Petroleum Regulations of 1974. The Ministry of International Trade and Industry is responsible for all licences for the refining, processing, and petrochemicals sectors, while the Ministry of Domestic Trade and Consumer Affairs is responsible for licences for the marketing and distribution of petroleum products.

### Ministry of Energy, Green Technology and Water

The Ministry of Energy, Green Technology and Water Malaysia (KeTTHA) was established on 9 April 2009 following a Cabinet reshuffle and restructuring. Prior to that, KeTTHA known as the Ministry of Energy, Water and Communications (MEWC) was established on March 27, 2004 through the restructuring of the Ministry of Energy, Communications and Multimedia. New functions and responsibilities assigned to KeTTHA include planning and formulating policies and programs that are aimed at the development of strong green technology in the country.

### Prime Minister's permission required for downstream operations

As per the provisions of the Petroleum Development Act, 1974 (incorporating amendments up to January 2006) in Malaysia, the business of processing or refining of petroleum, marketing, and distribution of petroleum products can be carried out by any company other than PETRONAS as long as permission given by the Prime Minister. This excludes companies that are licensed under the Gas Supply Act to supply gas to consumers through pipelines. In addition to this, the Prime Minister of Malaysia has the power to make regulations for downstream activities and development relating to petroleum and the marketing and distribution of petroleum and its products.

1 U S Energy Information Administration, 2013

PETRONAS reports directly to the Malaysian Prime Minister, and the oil and gas sector comes under the jurisdiction of the Economic Planning Unit of the Prime Minister's Department. This department is also responsible for gas pricing, while the Ministry of Domestic Trade and Consumer Affairs is responsible for the price of petroleum products.

**PETRONAS**

Following the enactment of the Petroleum Development Act, 1974, (PDA) the National Oil Corporation, known as PETRONAS (Petroliam Nasional Berhad in the Malaysian language), was established in 1974 as a state-owned enterprise in Malaysia. PETRONAS was granted exclusive ownership and control of the country's petroleum resources, including exploration and production. Export from Malaysia of crude petroleum and natural gas is controlled by PETRONAS.

**National Petroleum Advisory Council**

Following the enactment of the PDA, the National Petroleum Advisory Council was established to advise the Prime Minister on national policy, interests and matters pertaining to petroleum, petroleum industries, energy resources and their utilization.

**Energy Commission of Malaysia**

The Energy Commission of Malaysia is a statutory body responsible for regulating the energy sector including the piped gas supply to industries in Peninsular Malaysia and Sabah. The Commission, with the approval of the Minister, may grant a licence for the supply of gas through pipelines. This license is subject to the approval from local Government authorities. The Energy Commission ensures that the supply of piped gas to consumers is secure, reliable, safe and at reasonable prices.

**Department of Environment, Ministry of Science and Environment**

Oil and gas downstream projects require approval from the Department of Environment in the Ministry of Science and Environment as per the Environmental Quality Act. Companies need to prepare and Environmental Impact Assessment study report to obtain approval from the Department of Environment.

**Local Government authorities**

Various local Government agencies regulate specific industries. In addition to incorporating the company, specific licensing requirements apply to companies that may wish to undertake petroleum downstream operations.

### Competitive Industry Structure

**Regulated pricing of Petroleum products and natural gas practiced at large**

In Malaysia, the Government regulates the pricing of petroleum products and natural gas. Malaysia has significant energy subsidies in place, with by far the largest share of subsidies directed to petroleum products. Malaysians enjoy some of the cheapest diesel, and gasoline prices in Asia, and attempts at Government reform have been slowed by fear of a popular backlash against rising prices. Low, Government-controlled end-user gas price, which stands at USD 4.50/MMBtu for power plants, disincentives gas imports. As of August 2013, PETRONAS has had no success in its efforts to attract third parties to import LNG through its new Sungai Udang LNG import terminal, mainly due to unfavourable economics involving Malaysia's low domestic gas price. The Government has a medium-term aim to reduce and phase out fuel and gas subsidies to support PETRONAS financially.

In line with the Government's plan to phase out subsidies to liberalise the market by 2015, Malaysia launched the Subsidy Rationalisation Programme in 2010. The programme was designed to gradually remove subsidies every six months from 2010 to 2014. However, the changes to the gas subsidies occurred only once instead of the planned four times so far, and the Government subsequently suspended the programme in 2011 to focus on the cost of living. The Government has repeatedly mentioned that the current subsidy is not sustainable and could only revise the gas price once by increasing it by 1.1% in January 2014. The original schedule for complete price decontrol by 2015 is thus virtually impossible unless drastic changes are made to remove the subsidy.

**Monopolistic Industry structure:**

Malaysia has a well-developed downstream sector, which serves domestic demand as well as regional export markets. Most of the downstream infrastructure such as oil refineries and pipelines are located on the more developed Peninsular Malaysia (West Malaysia). However Sarawak (a Malaysian state) hosts Shell's gas-to-liquids (GTL) plant and the Bintulu LNG liquefaction complex, which is a key LNG supply source for Japanese consumers.

**Refining**

Malaysia has a refining capacity of about 580 thousand barrels per day in 2013[1]. The majority of Malaysia's oil refineries are located on Peninsular Malaysia and its national oil company, PETRONAS, has the largest installed refining capacity in Malaysia. Malaysia invested heavily in refining activities during the last two decades and is now able to meet most of its demand for petroleum products domestically, thus breaking its dependence on the refining industry in Singapore. PETRONAS, operates three refineries (320,000 bpd total capacity), while Shell operates two refineries (ownership- 51% Shell, 49% Public) (170,700 bpd total capacity) and Petron (San Miguel, Philippines holds 65% stake) operates one refinery (88,000 bpd).

Shell’s gas-to-liquids (GTL) facility in Bintulu is capable of converting natural gas into 14,700 barrels of GTL products per day. Malaysia also aims to construct a huge new oil refining and petrochemical complex in Johor state alongside a major oil transit route to the Far East, which will also provide the physical production capacity Malaysia needs to establish itself as a regional oil trading and storage hub.

**Natural Gas processing Units:**

Larger offshore gas fields in Sabah and Sarawak mainly produce gas for export through the giant Bintulu LNG complex (Sarawak). Malaysia has long been an LNG exporter to the Asia-Pacific region. The Bintulu facility consists of three LNG plants, MLNG - Satu, MLNG - Dua, and MLNG - Tiga, which have a combined capacity of about 23 million tonnes per year. PETRONAS has a 60% stake in the MLNG Dua and MLNG Tiga plants and a 90% stake in the MLNG Satu plant, with other stakeholders including Mitsubishi Corporation, Shell, JX Nippon, and the Sarawak Government.

Natural gas production from offshore Peninsular Malaysia fields is supplied to domestic market into Kerteh, from where it is then piped to cities in the West, including Kuala Lumpur. As demand for gas on Peninsular Malaysia has outstripped offshore production in nearby waters, Malaysia has turned to LNG imports to meet demand. A jetty-based floating LNG terminal with capacity of 3.8 mtpa was commissioned in April 2013 in Malacca (Maleka), near Kuala Lumpur. This was an easier solution than building offshore pipelines some 1000km from Sarawak where gas reserves are plentiful.

The LNG regasification terminal at Sungei Udang facility is managed by Regas Terminal which is wholly owned subsidiary of PETRONAS. The key to incentivising greater LNG imports into Malaysia through the new regasification terminals will be PETRONAS’ Third Party Access Scheme (TPA). The TPA is designed to allow third parties to import gas into Malaysia using PETRONAS’ gas transportation and processing infrastructure. Another two regasification terminals are planned to be built in Lahad Datu on the East coast of Sarawak and at Pengerang near Singapore.

[1] Source: BMI Report on Malaysia, 2013

## Pipeline infrastructure

Malaysia has a relatively limited oil pipeline network, given the island geography of the country, which has increased the importance of tankers for transportation and trucks for distributing products in the country. Malaysia's gas pipeline network is more extensive than its oil pipeline network. The Peninsular Gas Utilisation (PGU) Pipeline, owned and operated by Petrogas (a subsidiary of PETRONAS) on Peninsular Malaysia is the backbone of the country's gas pipeline network. Figure below shows gas and liquid product pipeline infrastructure in Malaysia.

*Figure L - 3: Map of Malaysia's Pipeline Infrastructure*


*Source: Theodora.com*

## Terminals and storage

Malaysia had 34 ports with oil terminals, refined product berths or liquid petroleum gas (LPG) terminals in July 2013. These facilities are mainly located along the eastern coast of Peninsular Malaysia and off the coast of the island in the form of floating storage, production, and offloading (FPSO), floating storage, and offloading (FSO) and single buoy mooring (SBM) facilities. Along the eastern coast of Peninsular Malaysia, the Port Dickson refinery has a number of refined product terminals owned by Shell through which oil products from the refinery are exported. The Melaka oil terminal is owned and operated by PETRONAS is also located in this region.

**Petroleum product marketing**

**Diesel and Gasoline:** The retail business particularly the dealers or operators of the service stations are the franchise or contract holders of the established oil & gas (O&G) petroleum companies while other outlets are small traders merely selling and dispensing of O&G products which complements their other trading businesses. PETRONAS is a major player in the retail and marketing segment competing with Royal Dutch Shell and Chevron (Caltex Oil Malaysia) and ConocoPhillips. Table below shows the number of retail outlets marketing refined petroleum products in Malaysia.

*Table L - 8: Retail Outlets Marketing Refined Petroleum Products in Malaysia*

| Company | Retail outlets |
|---|---|
| **PETRONAS** | 925 |
| **Shell Malaysia** | 900e |
| **ExxonMobil Malaysia** | 540 |
| **Caltex Oil Malaysia** | 420 |
| **LTAT (Armed Forces Fund Board, formerly BP Malaysia)** | 240 |

*Source: BMI Report on Malaysia, 2013*

**LPG:** The largest player in Malaysia's LPG sector is PETRONAS, which had an LPG market share of 56% in the 2012 financial year. In addition to PETRONAS, there are a number of other private LPG suppliers in Malaysia including Essogas and Omani Gas. LPG consumption in Malaysia is driven by the residential and commercial sectors as the industrial sector tends to consume more natural gas.

**Gas distribution and marketing**

The only company licensed by the Energy Commission to distribute natural gas on Peninsular Malaysia is Gas Malaysia Bhd, which is a joint venture between MMC-Shapadu (Holdings), Tokyo Gas-Mitsui & Co. (Holdings), and PETRONAS. Currently, MMC-Shapadu (Holdings) holds a 41% share of the company, 26% is publicly owned, Tokyo Gas-Mitsui Holdings owns a 19% share, and PETRONAS Gas Berhad holds 14%.

In Malaysia, the power generation sector consumes large quantities of natural gas and the gas based power stations account for 14,155.5 MW, or 46.3%, of Malaysia's operating installed capacity. They are the largest single contributors to the generation mix. Gas-fired generation has been supported by supplies from gas fields' offshore Peninsular Malaysia. However, growing supply pressure has forced Malaysia's state-owned oil and gas company PETRONAS to invest in an LNG regasification terminal, which will supply gas to the electricity sector among other customers.

### Health Safety and Environment guidelines

HSE legislative requirement in Malaysian oil and gas downstream segment is based on the guidelines of the following acts.

The Factories and Machinery Act 1967 (Revised 1974): Provides for the control of factories with respect to matters relating to the safety, health and welfare of person therein, the registration and inspection of machinery and for matters connected therewith.

The Environmental Quality Act 1974: Relates to prevention, abatement, control of pollution and enhancement of the environment and for purposes connected herewith.

The Petroleum Act (Safety Measures) 1984: This act consolidated laws relating to safety in the transportation, storage and utilization of petroleum.

The Occupational Safety and Health Act 1994: This act has provisions for securing the safety, health and welfare of persons at work, for protecting others against risks to safety or health in connection with the activities of persons at work, to establish the National Council for Occupational Safety and Health, and for matters connected therewith.

### Fuel Quality Norms in Malaysia[1]

Malaysia has legal requirements for the sulfur concentration in diesel fuels that generally align with those of the Euro 2. As on August 2013, the sulfur level in diesel fuel should be less than 500 mg/kg (500 parts per million (ppm)). Regulation requires sulfur levels in Malaysian gasoline to average no more than 500 parts per million (ppm). As a next step in fuel quality norms in Malaysia, Euro 4M norms will get implemented in Malaysia by 2015. The sulfur content for Euro 4M will be 50 ppm similar to Euro 4. While the benzene level in the Malaysian Euro 4M norms will be 3.5 percent volume in contrast to1% maximum by volume set for the Euro 4 specification.

### Summary of Observations

Malaysia has a well-developed downstream sector, which serves domestic demand as well as regional export markets. Malaysia invested heavily in refining activities during the last two decades and is now able to meet most of its demand for petroleum products domestically, thus breaking its dependence on the refining industry in Singapore. The developments in marketing infrastructure (storage and distribution infrastructure and retail outlets) were in tandem with developments on the refinery front. Malaysian oil refining and marketing industry is dominated by Malaysia's national oil and gas company, PETRONAS.

International oil companies like Shell are also operating refineries and marketing networks in Malaysia. Malaysia is seeking to keep value-added oil and gas production at home, rather than exporting crude oil and natural gas by constructing a huge new oil refining and petrochemical complex in Johor state, which will also provide physical production capacity to underpin Malaysia's aim to establish itself as a regional oil trading and storage hub and reforming its domestic gas market in order to supply its growing domestic manufacturing sector and diversify the economy.

The barriers to entry are minimal for foreign investors, although regulated pricing remained as an issue. Malaysia has established a set of long-term energy-related goals, incentives, and policies as part of its Economic Transformation Programme to promote increased productivity in the upstream sector and expansion of Malaysia's downstream oil and gas refining and processing capabilities.

In order to enhance domestic exploration and production activities and to meet the increase in demand for natural gas, PETRONAS started importing LNG in 2013 .Through the Petroleum Income Tax Act Amendment Bill, the Government introduced tax incentives for exploration activities in deep-water, marginal and stranded fields, which include a reduction of the petroleum income tax from 38% to 25% and an increase in the reimbursement for a company’s original investment from 70% to 100%. These incentives have contributed to the boost of exploration activities in fields that were not previously commercially viable. This has resulted in positive growth in gas production in 2014. Removing subsidies is important to encourage exploration of smaller fields for supply to the domestic market, to attract imports and to manage demand. Malaysia has not been able to move to international market parity pricing and is continuing to incur large budget deficits to subsidizing fuel prices due to political reasons.

[1] Status of Fuel Quality and Vehicle Emission Standards in Asia-Pacific, UNEP, 2013 August

# Nigeria

## Overview

As one Africa's most developed Oil economies Nigeria is a key determinant of what to do and what not to do. The lessons learnt from Nigeria are crucial to the development of Kenya's oil economy. In this section we will discuss Nigeria's midstream and downstream sector.

### Midstream Oil and Gas

Nigeria has been extracting associated gas since 1970s with overall current associated and non-associated gas production close to 36 bcm[1] that makes it the third largest gas producer in Africa after Algeria and Egypt. As has been the recurring trend, while most of the gas produced continues to be exported via LNG (62% in 2013), a substantial volume is flared leaving behind little gas for internal domestic consumption and with smaller volumes exported regionally via the West African Gas Pipeline. Nigeria consumed 224 Bcf of dry natural gas in 2012, less than 20% of its total production.

Currently over 80% of power generation is from thermal gas-and-oil-fired power stations with the remainder from hydro based plants. Natural gas fuels roughly 66% of total installed power generation capacity and with the 8$^{th}$ largest proven reserves of natural gas (5.1 tcm) in its backyard, gas production and availability for power generation holds the key to capacity expansion in Nigeria.

Some of Nigeria's oil fields lack the infrastructure to capture the natural gas produced with oil, known as associated gas. Much of it is therefore flared (burned off). According to the National Oceanic and Atmospheric Administration (NOAA), Nigeria flared slightly more than 515 Bcf of natural gas in 2011 - or more than 21% of gross natural gas production in 2011. Natural gas flared in Nigeria accounts for 10% of the total amount flared globally. In 2008, the Nigerian Government developed a Gas Master Plan that promoted investment in pipeline infrastructure and new gas-fired power plants to help reduce gas flaring and provide much-needed electricity generation. However, progress is still limited as security risks in the Niger Delta have made it difficult for independent oil companies (IOCs) to construct infrastructure that would support gas monetization.

Some of Nigeria's current challenges to gas sector development are similar to those faced in many emerging economies (MENA region) with abundant hydrocarbon reserves and with a pricing regime that is below the marginal cost of development of these resources. The causal sequence of events that follow is explained in the table below along with the bottlenecks that are created on the way:

| S No. | Cause | Effect | Constraints to development of gas sector |
|---|---|---|---|
| 1` | Associated gas production | 1. Gas viewed as a by-product of oil production<br>2. Possible gas flaring in absence of exports | 1. Perception of gas as a cheap by-product that is typically flared if not exported |
| 2 | Gas flaring | 1. Direct GHG emissions<br>2. Reinforces low value perception of gas and hence justifies low price<br>3. Loss of opportunity of gas utilization | |

[1] BP's statistical review of world energy 2014

| | | | |
|---|---|---|---|
| **3** | Ultra low prices[1] for gas for domestic use | 1. Creation of artificial domestic demand for gas<br>2. Rent seeking attitude of gas based industries<br>3. Unattractive domestic gas market | 2. Ultra low gas prices creates artificial demand and promotes populist measures at policy level |
| **4** | Creation of artificial domestic gas demand | 1. Demand-side lobbying: Pressure on supply sources to meet increasing domestic demand at low prices<br>2. Dependence on alternative and generally more expensive solutions such as liquid fuels, gas imports | 3. No incentive to participate and invest in development of upstream gas assets<br>4. Inadequate gas infrastructure vis-à-vis the booming domestic demand |
| **5** | Unwilling sellers for domestic market | 1. No incentive to invest in domestic gas processing and transmission infrastructure | |
| **6** | Limited gas infrastructure | 1. Stranded gas based industries<br>2. Gas flaring where export and domestic lifting not possible | |
| **7** | No exclusive law for extraction of gas, weak commercial agreements | 1. Recurrent instances of payment defaults<br>2. Lack of confidence in ability of buyers to pay and the perceived weakness of GSPA's in terms of protection they offer the supplier | 5. Weak regulatory and legal framework for enforceability of gas sector reforms |
| **8** | General instability in the region | (1) Bottleneck to infrastructure expansion and investment especially in onshore assets<br>(2) Hiving off existing onshore assets | 6. Continuation of pipeline attacks[2] and general instability especially in the northern region has recently resulted in IOCs hiving off their onshore assets. |

## Regulatory Structure

### Current Legislation

The primary piece of legislation regulating the exploration, production and distribution of petroleum in Nigeria is the Petroleum Act 2004 which vests in the Federal Government, the ownership of petroleum resources in Nigeria. Under the Act, all activities ranging from exploration to production and distribution of crude oil and natural gas may only be done with the consent of the Minister of Petroleum Resources who typically acts through the Department of Petroleum Resources (DPR) in the issuance of licenses and permits. The Act gives the Minister power to issue regulations necessary for the discharge of his/her duties under the Act. The

[1] Domestic gas prices are currently in the range of $1/mmBTU to $2.5/mmBTU.
[2] http://www.power.gov.ng/Power%20Summit/PTFP%2020140130%20CPTFP%20Power%20Summit.pdf

Petroleum Drilling and Production Regulations, is subsidiary legislation made pursuant to the Petroleum Act and it regulates natural gas, exploration and production activities.

**Current Legislation - Midstream - Oil & Gas**

The Oil Pipelines Act and the Oil and Gas Pipelines Regulations in particular, regulate the survey of routes, construction, operation and maintenance of oil and gas pipelines and associated infrastructure. The Pipelines Act and the oil and gas pipeline regulations bestow on the Minister the power to grant permits to survey routes for oil and gas pipelines and also licenses to construct, maintain and operate oil pipelines. Under the Petroleum Act, to operate a refinery, a license to construct and operate gas-processing facilities is required.

A Domestic (Gas) Supply Obligation (DSO) is imposed by the National Domestic Gas Supply and Pricing Regulations, on gas-producing companies in Nigeria which disallows them to export until they fulfill their DSO.

In addition, an Environmental Impact Assessment approved by the Federal Ministry of Environment (FMoE) is required for the construction and operation of any natural gas transportation and storage facilities.

**Current Legislation - Downstream - Oil & Gas**

The regulation on import of refined petroleum products into Nigeria also comes within the purview of the Department of Petroleum Resources (DPR). The DPR makes it mandatory for any company wishing to engage in the business of import of refined petroleum products to obtain an import permit. As regards to transportation of petroleum products within Nigeria, the Petroleum Regulations prohibit the transport of bulk petroleum without a license.

As per the Petroleum Act and the Downstream Petroleum Regulations, petroleum products can be imported into Nigeria only through prescribed ports, unless a waiver is obtained in writing from the Director of Customs allowing such importation through other ports.

Further, all facilities for the storage of imported petroleum products must be inspected by the DPR prior to licensing. The facilities must meet the specification for the storage of relevant classes of petroleum products.

| Year | Power sector reforms |
|---|---|
| **2000** | Privatisation mooted in the reforming National Electric Power Policy of 2000. |
| **2005** | ▪ Electric Power Sector Reform Act 2005 passed<br>▪ Power Holding Company of Nigeria(PHCN) established as successor to National Electric Power Authority (NEPA)<br>▪ Nigeria Electricity Regulatory Commission (NERC) put in place to regulate pricing and competition<br>▪ Unbundling of assets into 6 Gencos, 11 Discos<br>▪ National Integrated Power Projects (NIPP) initiative launched to boost generation capacity through construction of 10 new gas-fired plants totaling 4771 MW. |
| **2007** | Formulation of Multi-Year Tariff Order (MYTO) by the Nigerian Electricity Regulatory Commission (NERC) |
| **2010** | Formulation of Power Sector Reform Roadmap. Targets privatisation of PHCN assets by 2011. |
| **2012** | ▪ Bids approved for privatisation of PHCN assets<br>▪ MYTO 2 launched<br>▪ 1,350 MW capacity completed under NIPP |
| **2013** | Generation capacity under NIPP expected to reach 3,134 MW by end 2014, 4771 MW by 2015. |
| **2014** | $2.5 billion paid by preferred bidders for 15 out of total 18 assets of PHCN |

| Year | Gas sector reforms |
|---|---|
| **2004** | Commissioning of Strategic Gas plan for Nigeria.<br>Gas prices hovering at $0.1/mmBTU |
| **2007** | First attempt at overhauling of oil and gas industry. First draft of Petroleum Industry Bill (PIB) released. |
| **2008** | • Gas Master Plan launched. Sets out a scheme for gas monetisation for three markets: domestic, regional and exports. Emphasis on gas flaring reduction, etc.<br>• Nigeria Domestic Gas Supply and Pricing Regulations 2008 |
| **2009** | Inter-governmental agreement (Nigeria, Algeria and Niger) for the Trans-Saharan gas pipeline. |
| **2010** | ▪ Gas Aggregation Company of Nigeria (GACN) established to act as an intermediary between suppliers and buyers.<br>▪ Oil and Gas Industry Content Development Act 2010 implemented into a law. Local content to be increased from 40% to 70% |
| **2011** | $25 billion Gas Revolution Plan unveiled in 2011 |
| **2012** | PIB Draft 2012 released. |
| **2013** | ▪ Partial risk guarantee by World Bank to a 10-year Chevron Gas Supply and Aggregation Agreement (GSAA) to supply gas to 1,320 MW power plant in Lagos<br>▪ Split within the ruling party PDP further delays the passage of PIB 2012. |
| **2014** | PIB is yet to be passed in the Senate. Gas prices ~$2.5/mmBTU |

## Future Legislation

The latest draft of Petroleum Industry Bill (PIB), which was initially proposed in 2008, was submitted to the National Assembly by the Ministry of Petroleum Resources in July 2012. The delay in passing the PIB has resulted in low investment in new projects as there has not been a licensing round since 2007, mainly because of regulatory uncertainty. The regulatory uncertainty has also slowed the development of natural gas projects as the PIB is expected to introduce new fiscal terms to govern the natural gas sector. The PIB covers all aspects of the petroleum industry (upstream, midstream and downstream) by bringing together all existing regulations in the petroleum industry into a single document. One of the intents of the PIB is to stimulate gas supply to the domestic market and to require upstream investors to cooperate in using gas processing plants and other common infrastructure in order to efficiently supply gas to the domestic market.

Other key objectives of the PIB include the following:

- Setting up of new institutions and regulators in order to clarify and differentiate lines of responsibility. These include the National Petroleum Directorate, the Upstream Petroleum Inspectorate, the National Frontier Exploration Service, the **Downstream Petroleum Regulatory Agency** and the Petroleum Technology Development Fund.
- Increased gas utilization by way of DSOs and strict penalties on gas flaring.
- Liberalisation of the downstream sector including the sale of four state refineries.
- Fiscal change for the upstream segment: All companies will be liable to a company income tax, a Nigerian hydrocarbon tax, reduced allowances, and discountable items (cost recovery at maximum 80%) as well as volume/price-based royalties.
- Local content: Incentives for direct engagement in upstream activities for local players, with requirements for Nigerian manufactured content and local workforce.

## Ownership- Oil (Midstream)

Established in 1977, the Nigerian National Petroleum Corporation (NNPC) is the state oil corporation with interests in exploration activities, operational interests in refining, petrochemicals and products transportation as well as marketing. Between 1978 and 1989, NNPC constructed refineries in Warri, Kaduna and Port Harcourt and took over the 60,000-barrel Shell Refinery established in Port Harcourt in 1965.

## Midstream - Crude Transportation/Refining

On the midstream part, almost all crude oil transportation and refining infrastructure is owned by the State. All crude oil transportation is done by a subsidiary of NNPC and more than 98% of refining capacity is owned by NNPC.

## Midstream - Crude Transportation

The Pipelines and Product Marketing Company (PPMC) is the product distribution arm of the NNPC. PPMC receives crude oil from the NNPC unit, National Petroleum Investments Management Services (NAPIMS)[1]. PPMC then supplies the crude oil to NNPC's local refineries. However, the petroleum products are sometimes imported to supplement local production when the local refineries are unable to process enough for the country's needs.

## Midstream - Crude Refining

There are currently five refineries in Nigeria; of which four are owned by the Nigerian Government through the Nigerian National Petroleum Corporation (NNPC), while the fifth is owned and operated by Niger Delta Petroleum Resources (NDPR)[2].

**The Port Harcourt refinery**, a 210,000 barrels per day complex conversion plant is operated by the Port Harcourt Refining Company (PHRC) Limited, a subsidiary of the Nigerian National Petroleum Corporation (NNPC). The PHRC is made up of two refineries located at Alesa-Eleme, Rivers State. The old refinery has a refining name plate capacity of 60,000 barrels per day and was commissioned in 1965, while the new plant with name plate capacity of 150,000 barrels per day was commissioned in 1989. The plant utilizes bonny light crude oil to produce Liquefied petroleum gas (LPG), premium motor spirit (PMS), Dual Purpose Kerosene (DPK), Automotive Gas Oil (AGO), Low Pour Fuel Oil (LPFO) and High Pour Fuel Oil (HPFO).

**The Warri refinery** was established in 1978 with a refining nameplate capacity of 100,000 barrels per stream day and was debottlenecked to 125,000 barrels per stream day in 1987. The refinery is located at Ekpan, Warri, Delta State, and it is operated by the Warri Refining & Petrochemicals Company (WRPC) Limited, an NNPC subsidiary. The refinery was installed as a complex conversion plant capable of producing Liquefied Petroleum Gas (LPG), Premium Motor Spirit (PMS), Dual Purpose Kerosene (DPK), Automotive Gas Oil (AGO), and Fuel Oil from a blend of Escravos and Ughelli crude oils. WRPC has a petrochemical plant complex that produces Polypropylene, and carbon black from the propylene-rich feedstock and decant oil from the Fluid Catalytic Cracking unit (FCCU).

**The Kaduna refinery** has a name plate refining capacity of 110,000 barrels per day and is located in Kaduna, Kaduna State. The plant is run by the Kaduna Refining and Petrochemicals (KRPC) Limited, a subsidiary of the Nigerian National Petroleum Corporation (NNPC), and has a complex conversion configuration. The KRPC possesses a fuels plant commissioned in 1983 and the 30,000 MT per year Petrochemical Plant in 1988. The refining plant has two (2) distillation units that utilize Escravos and Ughelli crude oils for fuels production and imported heavy crude oil for lube base oil, asphalt and waxes. Products obtained from KRPC include Liquefied petroleum gas (LPG), Premium Motor Spirit (PMS), House Hold Kerosene (HHK), Aviation Turbine Kerosene (ATK), Automotive Gas Oil (AGO), Fuel Oil. The petrochemical plant produces Linear Alkyl Benzene (LAB).

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[1] PPMC - Mode of Operation (http://ppmc.nnpcgroup.com/AboutNNPC/ModeofOperation.aspx)
[2] DPR Operations (http://dprnigeria.org.ng/dpr-operations/downstream/refinery/)

**The NDPR refinery** is a 1,000 barrels per day topping plant located at Ogbelle, Rivers State. The plant is targeted at the production of diesel for its internal consumption and the excess is sold to immediate locality. The plant receives crude oil from the flow station operated by its upstream affiliate, the Niger Delta Exploration and Production (NDEP) Company, within its marginal field.

In the fourth quarter of 2013, respective average capacity utilization stood at 29.59%, 2.07% and 28.03% for KRPC, PHRC and WRPC[1]. The refining production capacities were underutilized due to incessant vandalism on the major pipelines that supply crude to the refining points.

Due to such low utilization levels, the refineries are unable to meet the domestic demand and Nigeria imports significant quantities of gasoline (PMS) and kerosene (HHK), though before 2006 it used to export these two products. Among the exports, naphtha and fuel oil form the largest amount.

### Ownership- Oil (Downstream)

#### Downstream - Petroleum Products Distribution/Marketing

The distribution and marketing of petroleum products has multiple players in Nigeria with state-owned NNPC's subsidiary, NNPC Retail controlling about 23% of the market, as per 2013 figures[2]. African Petroleum, Conoil, Mobil, Texaco, Total and Oando are other major players in the downstream business.

#### Downstream - Petroleum Products Pricing

The Petroleum Products Pricing Regulatory Authority (PPPRA) is responsible for setting the retail petroleum prices in Nigeria. The key components considered by the PPPRA include the landing cost of petroleum products, the margins for the marketers, dealers, and transporters, Jetty-Depot through-put and other charges and Taxes[3].

### Infrastructure – Oil (Downstream)

#### Downstream - Petroleum Products Distribution/Marketing

As mentioned earlier, petroleum products are sometimes imported to supplement local production when the local refineries are unable to process enough for the country's needs. Petroleum products that are imported or refined locally are received by the PPMC through import jetties and pipelines and distributed through pipelines to depots to designated retail outlets. There is also provision for using the rail system to move from some of the PPMC depots.

Vandalization of oil and gas pipelines facilities remains the single most critical challenge facing the oil and gas industry in Nigeria. Between 2010 and 2012, a total of 2,787 lines breaks were reported on pipelines belonging to the Nigerian National Petroleum Corporation (NNPC), resulting in a loss of 157.81mt of petroleum products worth about ₦12.53bilion.

### Ownership – Gas

#### Midstream - Gas Pipelines

The main pipeline transmission network in Nigeria is owned and operated by the Nigerian Gas Company (NGC), a subsidiary of NNPC. This comprises of the Escravos-Lagos Pipeline System (ELPS), also known as the Western Network, and the Alakiri-Obigbo Ikot Abasi Pipeline, also known as the Eastern Network. Other gas transmission pipelines are individually owned by the NLNG and the NNPC/SPDC/Total joint venture and dedicated to their respective operations.

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[1] NNPC website: 4th Quarter of 2013 statistics
[2] NNPC - Monthly Petroleum Information - Fourth Quarter of 2013 (http://www.nnpcgroup.com/Portals/0/NNPC_Files/Quarterly/36.%202013%20Fourth%20Quarter%20QPI.pdf)
[3] PPPRA - Pricing Template (http://www.pppra-nigeria.org/pricingtemplate.asp)

## Downstream - Gas Distribution/Marketing

At present, natural gas trading is undertaken by the NGC, which, owing to its ownership of transmission infrastructure acts as a gas merchant in Nigeria. The NGC created local distribution zones and grants franchises to private companies for the distribution of gas within the local distribution zones.

## Downstream - Gas Pricing

The Government has issued the National Gas Supply and Pricing Policy 2008, which provides a pricing framework for gas supplied to different sectors in the domestic market. The Policy and the Regulations underpin domestic natural gas trading in Nigeria. The fulfillment of domestic supply obligations is a prerequisite for any gas project.

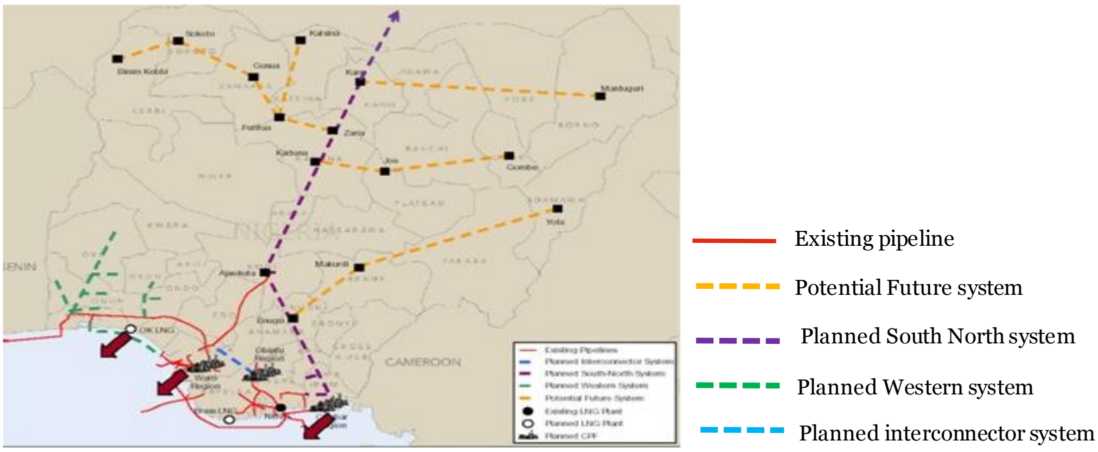
Currently, the Nigerian Liquefied Natural Gas Company (NLNG) is the only LNG company operational in Nigeria. It is jointly owned by NNPC, Shell, Total and Eni. LNG activities are generally regulated under the Petroleum Act and its subsidiary regulations, which include the Petroleum Refining Regulations. At present, there is no pricing regulation in the LNG sector.

The Nigerian Government plans to raise the price of gas for power plants to $2/MMBtu from $1/MMBtu currently by the end of 2014, and also raise the price of gas for industrial users to $3/MMBtu from $2/MMBtu. The Government has continued to develop new gas supply projects to meet the projected demand especially in the gas sector and for this the Government focuses on ensuring that gas prices are competitive.

## Infrastructure – Gas

## Midstream - Gas Transmission

The NGC's pipeline infrastructure comprises two un-integrated pipeline networks totaling approximately 1,100km: the Alakiri-Obigbo–Ikot Abasi Pipeline, otherwise known as the eastern network; and the Escravos–Lagos Pipeline System (ELPS), also known as the western network. The ELPS is a strategic 560km pipeline that transports gas from fields in the Niger Delta to Lagos, Nigeria's commercial centre, and then spurs at Lagos on to the West African Gas Pipeline (WAGP), which was developed by the NNPC, Chevron, Shell and the Governments of Nigeria, Ghana, Togo and Benin. The gas supply infrastructure is deemed completely inadequate for the emerging Nigerian gas sector. While most of the gas reserves are concentrated in the east, gas demand is strongest in the north and west which are poorly connected with the gas reserves.




**Cross-country pipeline projects:**

**Trans Saharan Gas Pipeline Project:** Nigeria and Algeria signed a memorandum of understanding (MOU) in 2002 for the 4,000 km gas pipeline to carry gas from Nigeria's Niger Delta region through the Republic of Niger to Algeria's Beni Saf export terminal on the Mediterranean Sea.

**West African Gas Pipeline (WAGP_:** The 678 km pipeline carries natural gas from Nigeria's Escravos region to Togo, Benin and Ghana. WAGP links into the existing Escravos-Lagos pipeline and moves offshore at an average water depth of 35 meters. The diameter of the onshore section is 30 inches (760 mm). The diameter of the offshore pipeline is 20 inches (510 mm) and the capacity is 5 billion cubic meter (bcm) of natural gas per year.

Construction on the pipeline began in 2005, and the pipeline was commissioned in the first quarter of 2010. There is some interest in expanding the pipeline further west to the Cote d'Ivoire.

On August 27th 2012, the West African Gas Pipeline was destroyed when pirates who had tried to board an oil tanker in an attempt to get away from the pursuing Togolese Navy, severely damaged the pipeline with their anchor. It resumed deliveries in July this year.

**Domestic pipeline network:**

The Nigerian Gas Company (NGC) operates 1,100 km of gas pipelines, with diameters between 4 and 36 inches. This system has a total transport capacity of more than 2 Bcf/d, as well as 14 compressor stations and 13metering stations. Currently, the Escravos to Lagos Pipeline System (ELPS), which was completed in the 1990s, is the main pipeline system for Nigeria's domestic gas consumption.

The NNPC is developing several new domestic pipelines. A 48 inch diameter pipeline has been proposed to transport gas to central and northern Nigeria, from Ajaokuta to Abuja to Kaduna, a distance of approximately 550 km. The project is expected to cost $US745 million. The approximately 400 km Aba – Enugu – Gboko Pipeline has been proposed to deliver natural gas to the eastern region of the country. The pipeline is expected to cost $US552 million. A current priority of the NNPC is the replacement of its domestic pipeline network. Most of the network is 15 to 20 years old, making it vulnerable to corrosion and leakage. In addition, the NGC plans to integrate all gas transmission systems in the country, creating the Trans Nigerian Pipeline. It is also planned that extensions of the systems would be made to the far northern states of Borno and Sokoto as well as to the central industrial state of Kano.

**Downstream - Gas Distribution/Marketing**

The NGC has several gas sale and purchase agreements (GSPAs) with gas producers for the gas (methane) produced in their projects. The NGC has also granted distribution licenses to local distribution companies. There are several gas distribution companies in Nigeria including Shell Nigeria Gas, a subsidiary of SPDC, and Gaslink Limited that distribute gas principally in the industrial areas in and around Lagos and in some parts of eastern Nigeria.

**Downstream - Gas Exports (LNG)**

The Nigerian Liquefied Natural Gas Company (NLNG), a joint-venture company established by the NNPC, Shell Petroleum Development Company (SPDC), Total and Eni, presently produces and stores the LNG produced. The company currently operates six trains which produces about 22 million tonnes per annum of LNG and about another 4 million tonnes per annum of LPG. The plans for the construction of the seventh train are at a more advanced stage.

Other LNG projects such as Brass LNG and the OKLNG are in the pipeline. There is a Chevron-operated Escravos Gas Plant which is currently being expanded and the Chevron Gas to Liquids (GTL) project, a joint venture with Nigerian National Petroleum Corporation (NNPC) and South Africa's Sasol, is currently underway.

### Policy for Third-Party Access

An application to the Minister of Petroleum Resources must be made for third-party access to oil and natural gas transportation pipelines and associated infrastructure. The Minister would then consider the application, in consultation with the applicant and the owner of the pipeline. The Minister would grant the application if satisfied that the pipeline can conveniently convey the substance which the applicant desires to convey. The terms and conditions of access are to be determined by agreement between the parties and failing this, such an agreement shall be determined by the Minister. The Minister may impose such requirements as he thinks necessary for the purpose of securing the access right of the applicant and regulating the access charge.

### Summary of Observations

The oil and gas industry in Nigeria is central to the growth and development of the Nigerian economy. According to the International Monetary Fund's estimates, presently, the Nigerian petroleum industry accounts for more than 95% of the country's foreign exchange earnings and over 80% of the Government revenues (EIA, 2012). Nigeria is the largest producer and exporter of crude oil in Africa and the sixth largest OPEC producer with proved reserves of more than 23 billion barrels.

Though the oil and gas industry was less constrained in earlier years, the constraints imposed by the federal policies in the later years have stifled the growth of the Nigerian oil and gas industry. Formation of the NNPC in 1977 and broadened federal intervention in the oil and gas business by regulating the upstream, midstream and downstream sectors of the industry have led to high levels of inefficiencies across the sector. The roles of policy maker (Ministry), regulator and the NOC often overlap. Due to the NNPC's tendency to cross-subsidize across its subsidiaries, the pipelines and refineries remain highly inefficient and create entry barriers for private players.

There exists a high domestic demand for all petroleum products. However, the domestic refining in Nigeria has not been able to meet the consumption thereby resulting in imports of refined petroleum products. Underutilization of refining production capacities due to incessant vandalism on the major pipelines that supply crude to the refining points has resulted in imports of refined petroleum products. The country has to bear the high costs of imports by paying for international price and other costs of landing the products in Nigeria.

Despite holding a global top-10 position for proven natural gas reserves, Nigeria's domestic consumption accounts for only about 20% of the gas produced in the country. Furthermore there is approximately 800 MMsc/d of available gas supply that equates to a potential power generation of 2800 MW as against the deliverable generation capacity (thermal only) of 4,181 MW in December 2013. The shortfall in gas availability thus impacts the power situation in Nigeria.

Petroleum product prices and domestic natural gas prices are currently regulated in Nigeria. Some of Nigeria's current challenges to gas sector development are similar to those faced in many emerging economies (MENA region) with abundant hydrocarbon reserves and with a pricing regime that is below the marginal cost of development of these resources. The Gas Master Plan provided some innovative solutions to the existing challenges to introduce Domestic Gas Supply Obligations (DSO) for upstream players to arrest the current shortfall of gas availability to the domestic sector and revision of gas prices in line with sector-wise affordability.

The Government has continued to develop new gas supply projects to meet the projected demand especially in the gas sector, and for this Government focuses on ensuring that gas prices are competitive. Towards this Nigerian Government currently have plans to raise the price of gas for power plants to US$2/MMBtu from US$1/MMBtu currently by the end of 2014, and also raise the price of gas for industrial users to US$3/MMBtu from US$2/MMBtu.

Overall, the lack of clarity on policy and the regulatory structure of the oil and gas industry as well as ignoring the development economics in oil-producing regions have led to a complex state of affairs in the Nigerian oil and gas industry. The Petroleum Industry Bill (PIB) is expected to change the organizational structure and fiscal terms governing the oil and natural gas sectors, if it becomes law. IOCs are concerned that proposed changes to fiscal terms may make some projects commercially unviable, particularly deep-water projects that involve greater capital spending. Some of the most contentious areas of the PIB are the potential renegotiation of contracts with IOCs, changes in tax and royalty structures, deregulation of the downstream sector, restructuring of the NNPC, a concentration of oversight authority in the Minister of Petroleum Resources, and a mandatory contribution by IOCs of 10% of monthly net profits to the Petroleum Host Communities Fund. The

Nigerian PIB 2012 has certain features that would benefit the growth of economy but it still misses out on the main issues that are plaguing the industry, which are, oil theft, pipeline damage and lack of refining investments.

## India

# Oil

### Overview of Petroleum Sector

Being the world's 4th largest energy consumer, India's energy mix is largely dominated by fossil fuels- mainly coal and oil & gas. The share of oil and gas in the total primary energy consumption currently stands at around 40% and is expected to remain so. The petroleum product basket consumed in the country comprises of a wide array of products namely Motor Spirit (Gasoline), High Speed Diesel (HSD), Kerosene, Naphtha, Liquefied Petroleum Gas, Aviation Turbine Fuel, Light Diesel Oil, Fuel Oil & LSHS, Bitumen Lubricants & Greases, Petcoke, LOBS etc. Domestic consumption of petroleum products over the last five years has grown at more than 17% per annum.

### Regulatory Structure

The Ministry of Petroleum & Natural Gas (MoPNG) is the apex agency entrusted with the responsibility of exploration and production of oil and natural gas, refining, distribution and marketing of petroleum products and natural gas, export and import of crude oil and petroleum products as well as conservation of petroleum products. Thus, the MoPNG oversees the activities spanning across entire value chain of oil industry.

In addition, the Petroleum and Natural Gas Regulatory Board (PNGRB) was constituted under The Petroleum and Natural Gas Regulatory Board Act, 2006 notified via a Gazette Notification dated March 31, 2006. PNGRB was established as the downstream sector regulator for regulating the refining, processing, storage, transportation, distribution, marketing and sales of petroleum products and natural gas. It does not, however, authorise refinery infrastructure construction, which is still controlled by the MoPNG, and it has no role in determining market pricing, or pricing policy.

### Era of Dominance of International Oil Majors

In India, the first oil deposits were discovered in 1889 in a place called Digboi in the state of Assam in India. Post the discovery of oil in the Digboi field, a new refinery was commissioned in 1901. Prior to India attaining independence in 1947, the entire oil industry in India was under the control of major international companies. The seven companies known as the "Seven Sisters" dominated the oil industry. These companies were referred to as the international majors; the five US giants, Exxon, Gulf, Texaco, Mobil and Socal (Standard Oil of California, later renamed Chevron), one British company (British Petroleum) and one Anglo-Dutch company (Royal Dutch Shell).

At the time of independence, about 91% of the country's total demand petroleum products were met primarily through imports. India's demand for petroleum products was 2.2 million metric tons (MMT), of which roughly 0.2 MMT were produced in the country and the balance was imported. During the first three years following independence, only 5 to 10% of the total petroleum products demand was produced in the country. In the subsequent years, the share declined to less than 5 per cent until the beginning of a new phase in refinery construction in 1954.

The marketing of petroleum products started in 1882 with the supply of kerosene by Standard Oil Company. At the time of Independence, Esso, Burmah Shell, Caltex and Indo-Burma Petroleum Company were marketing petroleum products in the country.

## Emergence of Public Sector Oil Marketing Companies

Post-independence, with the objectives to reduce dependence on imported petroleum products, steps were taken to augment refinery capacity in the country. The Government asked Burmah Shell, Standard Vacuum and Caltex to examine the feasibility of setting up refineries in India. Till this time, the import of products and their marketing and distribution were mainly controlled by these three foreign oil companies. Burmah Shell and Standard Vacuum agreed to set up a refinery each in the city of Mumbai in the state of Maharashtra and Caltex agreed to set up a refinery in the city of Visakhapatnam in the state of Hyderabad.

It was only in the mid-fifties that action was initiated towards setting up of public sector refineries. The first public sector refinery at Guwahati went onstream in January 1962 and in July 1964, the Barauni refinery was commissioned. The Indian Refineries Ltd. was already registered in August 1958 to manage them. Later on, when the Koyali refinery was built, the new company was entrusted with its management. In September 1964, the Indian Oil Company and Indian Refineries Ltd were merged into the Indian Oil Corporation. In September 1963, Cochin Refineries Ltd (CRL) was incorporated as a public limited company under a tripartite agreement between the Government of India holding 51% of the shares, Philips Petroleum Company of USA holding 25%, Duncan Brothers & Company Ltd of Calcutta holding 2% and the balance held by others. CRL went onstream in September 1966. The agreement of the Madras Refineries Limited (MRL) was concluded on 18 November 1965 between the Government of India with 74% participation in the initial equity capital, and the National Iranian Oil Company (NIOC) of Iran and Amoco India Inc. of USA. This refinery was commissioned in September 1969.

In 1959, the Indian Oil Company was formed for marketing of petroleum products, developing marketing infrastructure and distribution network. A major policy decision was also taken then to permit only the Indian Oil Company to handle imports of refined products and their marketing in the country.

## No entry barriers in refining sector, albeit Government approvals required

The refining sector was de-licensed in June 1998 after which refineries could be set up without specific Government permissions subject to other statutory requirements. As per the existing guidelines for Foreign Direct Investment in the petroleum sector, FDI in refining was permitted up to 26% (public sector holding of 26% and balance 48% by general public). In case of private Indian companies, FDI in refining was originally permitted up to 49%. Since then, the Indian petroleum-refining sector has been opened to full foreign investment, as the Cabinet has decided to allow 100 % FDI; foreign investors investing in the petroleum refining sector will not be required to obtain any clearances from the Foreign Investment Promotion Board (FIPB). They only have to notify the country's central bank- the Reserve Bank of India. However, in case the project is taken up along with a PSU, FDI is restricted to 26%. With de-licensing, the Jamnagar refinery of Reliance Industries Limited (RIL) was commissioned on 14 July 1999 with an installed capacity of 668,000 barrels per day. Following this, Essar Oil Limited, another private sector Oil Marketing Company also commissioned another refinery.

## Move towards increased private sector participation in marketing subject to Government regulations

The authorisation to market transport fuels (Diesel and petrol) and other deregulated fuels (LPG, ATF) can be granted by the MoPNG subject to the eligibility criteria. However, in February 1993, the Government introduced parallel marketing of LPG, kerosene and low sulphur heavy stock by private parties in order to increase the availability of these products. Accordingly, imports and pricing of these products for parallel marketing were decontrolled under the scheme. The objective of this scheme was to enable the affluent sections of the society to buy these products from the open market.

Import, blending and marketing of lubes was fully deregulated in November 1993. In order to promote foreign investment and transfer of technology for modernisation and upgradation of lubricants manufactured in the country, the Government has approved formation of several joint venture companies. In this process, more than 30 multi-national companies (MNCS) are presently operating in India such as Mobil, Shell, Caltex, Fuchs, Exxon, Elf, Mitsubishi and Gulf.

**Move towards pricing reforms**

In April 2002 India abolished the Administrative Pricing Mechanism (APM) that controlled the price of petroleum products. Despite the dismantling of the APM regime, the Public Sector Oil Marketing Companies (OMCs) have not yet been granted freedom to revise the prices of the major petroleum products such as petrol, diesel, kerosene and LPG, which account for more than 60 per cent of the total consumption of petroleum products, in tandem with international crude oil price movements.

Not aligning the domestic selling prices of petroleum products with the international prices has adverse implications for Government finances and the development of the petroleum sector. The financial health of the public sector oil marketing companies will deteriorate as a result. In such a scenario, public upstream companies and their share-holders continue to share their profits with downstream companies and consumers of products other than diesel, petrol, LPG and kerosene would continue to cross-subsidise these products. Private companies like Reliance Industries Limited have closed down their retail outlets. They found it difficult to compete with public sector oil marketing companies due to the selling price-differentials between public and private sector retail players. The public sector oil marketing companies - Indian Oil Corporation, Bharat Petroleum Corporation, and Hindustan Petroleum Corporation are selling fuel below the production cost. While these state-owned oil retailing companies are compensated by the Government for their revenue losses, a similar mechanism is not available to private sector players. This ad-hoc price control policy has created a non-level playing field between the public and private sector and has hampered investment in downstream marketing.

As a move towards petroleum product pricing reforms, gasoline prices were decontrolled in June 2010. The partial deregulation of diesel was announced in January 2013 wherein OMCs were allowed to raise the price of diesel by 50 paise per litre every month till all their under-recoveries are wiped off. This partial deregulation of diesel by virtue of price rise by 50 paise per litre every month is expected to continue until there are no under-recoveries for OMCs. However, it is expected that diesel prices may be completely deregulated in next few years as the Government cannot afford to give more subsidies with the alarming levels of current account and fiscal deficits. Further to this partial deregulation of diesel, in order to reduce the LPG subsidy burden, a cap was imposed on the number of subsidized LPG cylinders to be sold to households to 12 per household per annum.

## Industry Structure

India's publicly-owned integrated refining and marketing companies, referred commonly to as Oil Marketing Companies (OMCs), are the dominant players in the country's downstream petroleum sector.

The refining segment is dominated by three National Oil Companies (NOCs) i.e. Indian Oil Corporation Limited (IOCL), Bharat Petroleum Corporation Limited (BPCL) and Hindustan Petroleum Corporation Limited (HPCL) and their subsidiaries. These OMCs are majority owned by the Government of India and formally come under the jurisdiction of Ministry of Petroleum and Natural Gas (MoPNG). Although these Public Sector OMCs are under the aegis of Government of India, they enjoy autonomy in their day-to-day operations.

**Terminals and storage**

The retail marketing of petroleum products in India is done primarily by the Public Sector Oil Marketing Companies (OMCs) i.e. Indian Oil Corporation Ltd (IOCL), Hindustan Petroleum Corporation Ltd (HPCL), Bharat Petroleum Corporation Ltd. (BPCL), Numaligarh Refinery Ltd. (NRL), Mangalore Refinery & Petrochemicals Ltd. (MRPL) and private companies such as Reliance, Essar, Shell. The PSUs dominate the marketing and distribution infrastructure such as terminals, storage, retail outlets etc. to supply and distribute the petroleum products across the length and breadth of the country. To develop storage and allied facilities, the oil industry in India has taken up various additional product tankage programmes for petroleum products of mass consumption, commensurate with the growth in demand of petroleum products.

India does not have any compulsory stock policy with regards to petroleum products as the country has surplus refining capacity in meeting domestic demand. Since India depends on about 80% of crude oil requirement of the domestic refineries there exist oil security concerns. Taking this into account the Government of India has set up strategic crude oil storage of 5 Million tonnes at three locations in the country. These strategic storage facilities are being managed by the Indian Strategic Petroleum Reserves Limited (ISPRL), a Special Purpose Vehicle, owned by the Oil Industry Development Board (OIDB). These facilities are in underground rock caverns on the east and west coasts so that they are readily accessible to the refining sector.

### Transportation

Transportation of petroleum products in the country occurs via four modes: pipelines, rail, coastal and road. Most of the refineries have rail sidings. The share of rail in transportation of petroleum products witnessed a decline in recent years with increasing movement by petroleum product pipelines. Considering various advantages of pipeline transportation, the product pipeline network in the country is being expanded to transport increasing requirements of petroleum products. In view of this, the Government of India has embarked upon an ambitious programme of developing product pipelines through subsidiaries and joint ventures (JV) for different pipelines with private participation.

The authorisation to lay, build, operate and maintain petroleum product pipelines is granted to companies by PNGRB through a competitive bidding process. Private companies are allowed to build and operate pipelines in the country. For example Reliance group is currently operating a dedicated pipeline for transporting their liquid products within the Western part of India. Bidding as a consortium or JV is also allowed to build and operate pipelines. As per the PNGRB's regulations, pipeline operating companies have to grant a minimum of 25% of their capacity to other oil marketers. The transmission charge for petroleum product pipelines is determined based on competitive bidding and is regulated by the PNGRB. As per the PNGRB regulations on 'Petroleum and petroleum product transportation tariff determination', the pipeline transportation tariff is determined by benchmarking against alternative modes of transport, i.e. rail at a level of 75% on a train load basis for equivalent rail distance along the petroleum product pipeline route.

Numaligarh Refinery Limited, a public sector oil company is currently constructing a petroleum product pipeline from the Eastern part of India to Bangladesh to transport about 1 Million Metric tonnes of petroleum product with grants from Ministry of External affairs, Government of India.

## *Gas*

### Overview

Natural gas mainly serves as a substitute for coal for electricity generation and as an alternative for LPG and other petroleum products in the fertilizer and other sectors in India. The country was self-sufficient in natural gas until 2004, when it began to import liquefied natural gas (LNG) from Qatar. Because India has not been able to create sufficient natural gas infrastructure on a national level or produce adequate domestic natural gas to meet domestic demand, India increasingly relies on imported LNG. India was the world's fourth-largest LNG importer in 2013, following Japan, South Korea, and China, and consumed almost 6% of global consumption, according to data from IHS Energy.

As with the oil sector, India's Ministry of Petroleum and Natural Gas (MoPNG) oversees natural gas exploration and production activities. The MoPNG's Directorate of Hydrocarbons functions as an upstream regulator and monitors natural gas production and coal-bed methane projects. Until 2006, the Gas Authority of India Limited (GAIL) functioned as a near-monopoly operating India's natural gas pipelines. However, the Government began to reform gas pricing and created the Petroleum and Natural Gas Regulatory Board to regulate downstream activities such as distribution and marketing

Until the formation of Petroleum and Natural Gas Regulatory Board in 2007, the midstream and downstream gas sector was totally under the purview of the State, with Government determining the prices of natural gas through an administered price mechanism (APM) as well as the pipeline tariffs for gas transportation.

## Evolution of Natural Gas Sector

### Midstream[1]

Oil India Limited (OIL) was the first Indian company, to start selling and distributing gas in Assam (North-East India) in the sixties. Later on, the Oil & Natural Gas Commission (ONGC) and Assam Gas Company also laid natural gas pipelines for sale of gas to major industries and tea gardens. In Gujarat, the ONGC started selling its associated gas to the neighboring industries in the seventies and pipelines were laid / owned by either the ONGC or the customer.

The ONGC had major oil / gas finds in Mumbai High (Western Coast of India) in the seventies and the first offshore pipeline was laid up to Uren in Maharashtra (West Coast) for supply of gas mainly to the industrial consumers around Mumbai – like MSEB, Tatas, RCF etc. The ONGC laid a gas pipeline network for distribution of this gas in Mumbai region. Some of the dedicated pipelines were also laid by the customers themselves.

In the late seventies, a major gas reserve was found in the South Bassein in Mumbai Offshore having its landfall point at Hazira in Gujarat. The first major cross-country pipeline in India was conceptualized in the early eighties to supply this gas mainly in the fertilizer and power sectors. Gas Authority of India Limited (GAIL) was formed in August '84 to construct and operate the HVJ (Hazira- Vijaipur-Jagdishpur) pipeline and also to act as the nodal agency for transmission, distribution and processing of natural gas in India. The 1700 KM. long HVJ pipeline was commissioned in phases between 1987 and 1989.

Thereafter, the GAIL looked after the entire transmission and distribution of natural gas in India through the takeover of existing assets from the ONGC and laying of new high pressure gas pipelines in states like Andhra Pradesh, Tamil Nadu & Tripura to connect gas sources and consumers. In 2006, Reliance India Limited (RIL) commissioned its East-West pipeline to bring the gas from its own offshore field on eastern coast of India.

Following the creation of the sector regulator, the PNGRB in 2007, the authorization to build and operate a gas pipeline must be granted by the PNGRB. The tariff is determined by the Board on the basis of 12% post tax Internal Rate of Return (IRR) on investments made by the owner of the pipeline system and allowable Operating & Maintenance Costs for the estimated Project Life.

### Downstream

In the eighties, the GAIL initiated techno-economic feasibility studies for Gas Distribution in the metro cities of Mumbai and Delhi through Sofragaz & British Gas respectively. Based on the encouraging recommendations of these studies, Government of India approved gas allocation for Mumbai and Delhi.

Mahanagar Gas Limited (MGL), a Joint Venture company of the Gas Authority of India Limited (GAIL), British Gas and the Government of Maharashtra was incorporated in May 1995 for supply and distribution of Natural Gas to domestic, commercial, small industrial consumers and Compressed Natural Gas (CNG) to vehicular consumers in Mumbai through its integrated gas pipeline network.

Similarly Indraprastha Gas Limited (IGL), a JV of the GAIL and Bharat Petroleum Corporation Limited (BPCL) was incorporated in December 1998 to developing a distribution network for the residential, transport and commercial consumers in Delhi. Gujarat Gas Company Limited (GGCL), promoted by British Gas developed the gas distribution in Surat, Bharuch & Ankleshwar districts in the western state of Gujarat.

## Pricing

[1] Ministry of Petroleum & Natural Gas, Government of India – Report on CGD in Mumbai – Jan 2003

**Midstream**

Prior to 1987, natural gas produced by the ONGC and OIL was sold at prices largely determined by the producers themselves. The principles of thermal equivalence with coal as well as parity with other alternative fuels were taken into consideration by the producers while fixing gas prices.

In 1987 the Ministry of Petroleum and Natural Gas decided to examine the issue of natural gas pricing thereafter decided to have an administered pricing structure for natural gas. The Government administratively decided to fix the price of natural gas at Rs.1400 / '000 SCM at landfall and a flat rate of Rs.2250 / '000 SCM for gas transported along the HVJ line. In 1989 the Government again decided to reexamine the gas pricing structure and introduced a gas sales price of Rs.1550 / '000 SCM at landfall to be increased each year by Rs.100 until it reached Rs.1850 / '000 SCM. Transportation charges were set at Rs.850 / '000 SCM for transportation along the HVJ line.

In 1996 the Sankar committee was established by the Government to review prices, with some consideration given to the impending need for gas imports and the effects of parity in pricing with alternative fuels. The committee decided that import parity pricing would be too steep a transition and recommended rates for producers of Rs.1800 / '000 SCM for the ONGC and Rs.1900 / '000 SCM for OIL. Transportation charges were set at Rs.1150 / '000 SCM for transportation along the HVJ line. The consumer prices were set at the sum of producer and transportation rates with an additional Rs.250 crores to be contributed to the Gas Pool Account taken from the gas revenues collected from consumers.

The transportation tariff for HVJ (Rs. 1150/ '000 SCM) had been approved by the Govt. of India on the basis of a 12% post tax Internal Rate of Return (IRR) on investments made by the GAIL for the HVJ pipeline system and allowable Operating & Maintenance Cost for the estimated project life. For other pipelines, the GAIL and its consumers entered into contracts with mutually agreed tariffs calculated on the same basis as that for the HVJ pipeline. As of now, these tariffs do not require any approval by any statutory agency or the Government of India.

In May 2010, the MoPNG increased APM gas prices from USD 1.79/MMBTU to USD 4.2/MMBTU, a price level similar to KG-D6 gas. The price was to be fixed in USD and converted in rupees based on the exchange rate prevailing in the previous month. The price of USD 4.2/MMBTU excludes any transportation charge, margin and taxes. Gas supplied under the Administered Pricing Mechanism (APM) constitutes about 60 per cent of current domestic production, with the remainder being contracted directly with upstream production. Producers.

The Administered Pricing Mechanism does not apply to imports of LNG, where importers negotiate directly with gas buyers. So the landed price for the end customer would be determined by adding to the contracted price between the supplier and importer, the margin charged by the importer as well as pipeline transportation charges and applicable taxes.

The Government of India is currently considering natural gas price hikes, to increase the domestic gas price from USD 4.2 per MMBTU to USD8.4 per MMBTU based on the recommendations of the Rangarajan Committee formed to look into the Production Sharing Contract Mechanism in the Indian petroleum industry. The Rangarajan Committee formulae calls for pricing domestic gas based on the twelve month average of prevailing prices at international hubs in the US and UK as well as the actual cost of LNG imports into Japan and the rate at which India imports LNG.

However, due to the concerns about the adverse impact on end use segments such as the fertilizer and power sectors as a result of implementing the new formula, the new Government is currently reviewing the proposed price hike. It is expected that, the Government of India may increase gas prices in the near future to enhance domestic gas production as higher prices would push exploration companies to increase exploration and production thereby helping the country reduce its dependence on imports. Once the Government makes a decision, the prices are expected to apply uniformly to all producers, be it state-owned firms like OIL and the ONGC or private sector companies such as Reliance Industries.

**Downstream**

For the industries in Delhi, the GAIL had been charging distribution tariffs in the HVJ pipeline format- i.e. on the basis of 12% post tax IRR on investments made plus standard Operating & Maintenance Cost for the estimated Project Life. Other companies after taking delivery of gas at the administered price for their City Gas Stations from the GAIL charged their consumers using different methods.

MGL's tariff for natural gas supplied to residential, commercial and industrial sectors in Mumbai was based on some discount over alternate hydrocarbon fuel for each sector. MGL charges on cost-plus method for CNG supply to the transport sector. Currently, MGL is supplying gas to industrial / commercial consumers on the basis of contracts and to its automobiles & domestic consumers on a retail basis. IGL's pricing in Delhi for CNG was based on a Return on Investment model vis-à-vis full cost and capacity buildup to meet demand. For other sectors, IGL supplies gas at 10% less than corresponding alternate fuel. GGCL's prices were market determined.

### Creation of a Regulator

In 2002, the Government introduced the Petroleum Regulatory Board Bill to provide for the establishment of the Petroleum Regulatory Board to regulate the refining, processing, storage, transportation, distribution, marketing and sale of petroleum and petroleum products excluding production of crude oil and natural gas. This eventually led to the creation of the Petroleum and Natural Gas Regulatory Board in year 2007, which became the regulator for midstream and downstream gas sector.

The main functions of the Board involve authorizing entities to set up LNG terminals, lay and operate gas pipelines, operate CGD networks as well as regulate transportation tariffs for gas pipelines and CGD networks.

### Regulatory Structure

The following indicates the segment-wise regulatory structure of India:

| | Upstream | Midstream | Downstream |
|---|---|---|---|
| **Governing ministry** | The Ministry of Petroleum and Natural Gas (MoPNG) | | |
| **Legal framework** | The Oilfields Regulation and Development Act, 1948<br>The Petroleum and Natural Gas Rules, 1959 | The Petroleum and Natural Gas Regulatory Board (PNGRB) Act, 2006 | |
| **Regulator** | The Directorate General of Hydrocarbons (DGH) | The Petroleum and Natural Gas Regulatory Board (PNGRB) | |
| **Policies and regulations** | The New Exploration Licensing Policy (NELP)<br>The Coal Bed Methane (CBM) Policy | 1. Authorisation<br>2. Tariff<br>3. Access code<br>4. Affiliate Code of Conduct | 1. Authorisation<br>2. Tariff determination<br>3. Exclusivity for CGD networks<br>4. Technical standards |
| **Foreign direct investment (FDI) policy** | 100% under automatic route | 100% under automatic route | <u>Refining</u>: 49% in case of Public sector units (PSU) via FIPB route and 100% in case of private companies<br><u>Other than refining</u>: 100% under automatic route |

The regulatory agencies are supported by some of the following key central Government ministries and policy formulating bodies:

- **The Planning Commission**: It is the nodal agency responsible for building a long-term strategic vision for India and deciding its priorities. It works out sector-specific targets and provides promotional stimulus to the economy to grow it in the desired direction. For the hydrocarbon sector, the Planning Commission has formulated policies such as the Integrated Energy Policy and Working Group plans for the sector, etc.

- **The Ministry of Finance (MoF)**: It decides on tax and fiscal matters relating to the country's hydrocarbon sector.

- **The Ministry of Law (MoL)**: It advises on legal issues related to various policies and regimes relating to the hydrocarbon sector.

- **The Directorate General of Hydrocarbons (DGH)**: It was established in 1993 under the administrative control of the Ministry of Petroleum and Natural Gas. Its objectives are to promote sound management of the oil and natural gas resources with a balanced consideration for the environment, safety, technological and economic aspects of the petroleum activity.

### Infrastructure – Midstream

The two most important companies operating India's large gas pipeline system are the GAIL and Reliance Gas Transportation Infrastructure Limited (RGTIL). GAIL, the state-owned gas transmission and marketing company, operates two major gas pipelines in northwestern India with a combined length of 3,328 miles: the Hazira-Vijaipur-Jagadishpur (HVJ) line running from Gujarat to Delhi, and the Dahej-Vijaipur (DVPL) line. The company primarily services the northwestern region of India and makes up over 70% of the country's pipeline network.

The GAIL has around 6000 km of new pipelines under construction which would increase regional linkages. RIL and the GAIL were awarded the contracts to start the second phase of construction of trunk pipelines to transport gas from the Krishna-Godavari Basin to the southern parts of the country. While the GAIL has started construction on 4 out of its 5 projects, the Government cancelled RIL's authorizations in October 2012 citing lack of progress made in the construction. The poor performance of the RIL fields in the K-G basin has changed the business case for these pipelines. In terms of regulation, in 2006, when the GAIL's monopoly on gas transport was abolished, the PNGRB also set up the Access Code requiring one third of the capacity be made available to third-parties, with the PNGRB setting the tariffs.

Reliance Gas Transportation Infrastructure (RGTIL, owned by RIL) is the biggest private investor in the gas transmission structure and brought the 881-mile East-West pipeline online in 2009 to link the promising KG-D6 gas field to the GAIL's pipeline network and demand centers in the northern and western regions. However, RIL's East-West pipeline remains relatively underutilized as a result of lower-than-expected production from the KG-D6 field. Other players like Assam Gas Company and Gujarat State Petronet Limited (GSPL) have significant pipeline assets that service regional demand centers in northeastern India and Gujarat, respectively.

### Infrastructure – LNG

There are four existing LNG terminal in India - Dahej 10 mtpa, Hazira 3.5 mtpa, Ratnagiri 5 mtpa, Kochi 2.5 mtpa. The Dahej and Kochi terminals are 100% owned by Petronet. Hazira is majority owned by Shell with the rest held by Total. Ratnagiri (Dhabol) is owned by a consortium which includes the GAIL and the NTPC (India's largest power producer) as major stakeholders. With the exception of Kochi, these terminals are situated along India's West coast, close to existing gas infrastructure, initially developed to distribute gas from fields onshore and offshore in the state of Gujarat. Plans are now mooted for a possible 45 mtpa of additional capacity across 10 projects situated along both the East and West coasts. At least three more planned terminals are in detailed planning stages, FEED or are in tendering stages. Furthermore, both Dahej and Hazira are set to be expanded: Dahej to 15 mtpa by Q1 2016 (Gujarat State Petroleum Corporation, GSPC, has taken 2.25mtpa capacity in the expansion) and Hazira to 10 mtpa also by 2016.

In terms of regulation, in April 2012, the PNGRB proposed Open Access for a third of capacity at regasification terminals to be made available to third parties at fair and competitive price. This would allow new players to enter into LNG trade without actually investing in infrastructure. They only need to partner with terminals and pipeline operators.

### Infrastructure – Downstream

At present, the CGD networks are present in 55 cities in India, 31 of which were authorized by the Government prior to the formation of the PNGRB. An entity seeking authorization to operate CGD networks in India needs to be incorporated as per the Companies Act of India. Authorizations for CGD networks are awarded through bidding rounds for cities with gas pipeline connectivity; at present, the fourth round of bidding is still going on.

### Summary of Observations

Insufficient pipeline infrastructure and lack of a nationally integrated system are key factors that constrain natural gas demand in India, although the GAIL and other companies are investing in several pipeline projects. The Indian Government has considered importing natural gas via pipeline construction through several international projects, although many of these have proved unfeasible. In 2005, negotiations over a transnational pipeline between the Indian and Bangladesh Governments fell through. In 2006, India withdrew from the Iran-Pakistan-India (IPI) pipeline project. However, the Government still participates in a pipeline project to import natural gas from Turkmenistan to India. The Turkmenistan-Afghanistan-Pakistan-India (TAPI) project, also known as the Trans-Afghanistan Pipeline, has seen a decade of discussion, although major geopolitical risks and technical challenges have prevented the project from actually starting.

Though PNGRB has hoped to spread CGD networks to more than 200 cities within the first decade of its existence, it has barely able to authorize 20 cities in 7 years of its existence. One of the main reasons for this is lack of natural gas availability in India and imported gas (LNG) proving too expensive for price sensitive consumers. Cities like Mumbai and Delhi have seen high success in implementation of CGD networks primarily due to a Judicial push by the High Court that mandated the use of natural gas in transport segment.

With indigenous production lagging behind, LNG imports are expected to meet India’s rapidly rising demand for gas. Many new terminals are being considered or are in late planning stages and most existing terminals have plans for expansion. India’s LNG import capacity and hence LNG imports are expected to double before 2020.

The Government of India is currently considering a natural gas price hike based on the recommendations of the Rangarajan Committee which was formed to look into the Production Sharing Contract Mechanism in the Indian petroleum industry. However, due to the concerns about the adverse impact on end use segments such as the fertilizer and power sectors with the implementation of the new formula, the new Government is currently reviewing the proposed price hike. However it is expected that, the Government of India may increase gas prices in near future to enhance domestic gas production as higher prices would push exploration companies to explore and produce more and help the country reduce its dependence on imports.

# *Trinidad & Tobago*

## Overview of the Gas Sector

Trinidad and Tobago has developed a large downstream gas sector for a country of its size. Despite having a relatively low reserves base currently estimated to be 12 Tcf (with a peak of 20 Tcf in 1999), domestic consumption of over 22 Bcm/yr. is relatively large for a country with a population of 1.3 million (equal to only 0.02% of global population).[1]

Over a span of 50 years it has developed a large downstream gas sector relative to its share of reserves and in 2013 5.7% of global Liquefied Natural gas (LNG) trade was attributable to Trinidad and Tobago. However, a large proportion of domestic demand (approximately 70%) is for the production of ammonia and methanol which, like LNG, are exported to international markets. In 2013 Trinidad and Tobago ranked as the number one exporter of ammonia and number two exporter of methanol globally.[2] As of 2011 it also generated 99.7% of its electricity from natural gas.[3]

The1.5 GW of electric generation capacity only accounts for around 3 Bcm of gas demand per year. A large part of the power produced is supplied to the export industries. The Government has recently constructed a new 720 MW CCGT. Only 225 MW has been commissioned and will largely replace older less efficient power plants. There is some demand for gas in the production of metals and cement, but this is also small at around 2.5 Bcm/yr. [4]

## Regulatory structure

Trinidad and Tobago's downstream Petroleum Sector is mainly governed by The Petroleum Act, 1969 and supporting regulations. The Petroleum Act vests regulatory power of the downstream oil and gas sector in the Minister for Energy and Energy Affairs, some of which is delegated to the Trinidad and Tobago Bureau of Standards (for example standards certification for compressed natural gas (CNG) systems). Other key legislation includes The Petroleum Production Levy and Subsidy Act, The Petroleum Taxes Act and The Unemployment Levy Act.

The Minister also has the power to set prices (and deemed prices for tax purposes) for vertically integrated operators. The Minister may delegate any of the above mentioned responsibilities.

Any dispute involving the Minister and a licensee is handled via arbitration, with each party selecting an arbitrator and the Chief Justice selecting an umpire.

### Licencing

In order to establish any petroleum operation in Trinidad and Tobago, including a refinery, petrochemical plant or marketing station, a licence from the Minister is required. Further approval of the Minister is also required in order to expand or substantially alter existing operations.

Refinery and petrochemical licencees are required to give preference to indigenous oil and gas in their processing operations, as well as to the manufacturing of products that are required for domestic consumption (where economically feasible and in the public interest). Trinidad and Tobago does not impose any export restrictions on licencees, save for the option of the Minister to demand delivery in kind for the Government share of product under Petroleum Sharing Contracts (PSCs). However, in the event of a deemed shortage, the

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[1] R. Jobity, *Tertiary Natural Gas Workshop: July/August 2013*, (2013),http://ngc.co.tt/wp-content/uploads/pdf/NGC_Webinar_The%20Structure_History_and_Role_of_the_Natural_Gas_Industry_2013-08-22.pdf
[2] U.S. Energy Information Administration, *Country Analysis Note*, (2013), http://www.eia.gov/countries/country-data.cfm?fips=TD
[3] The World Bank, *Electricity production from natural gas sources (% of total)*, (2014), http://data.worldbank.org/indicator/EG.ELC.NGAS.ZS
[4] R. Jobity, *Tertiary Natural Gas Workshop: July/August 2013*, (2013), http://ngc.co.tt/wp-content/uploads/pdf/NGC_Webinar_The%20Structure_History_and_Role_of_the_Natural_Gas_Industry_2013-08-22.pdf

Minister may require a refining licensee to deliver to the Government at prevailing wholesale prices up to ten per cent of manufactured product for domestic use.

The National Gas Company (NGC) has a monopoly on the purchase, distribution and marketing of natural gas within Trinidad and Tobago.

### The role of state owned companies in the development of the gas sector

State owned companies have been a key policy tool for the development of Trinidad and Tobago's downstream gas sector. Demand for natural gas was pioneered in 1953 by the state owned Trinidad and Tobago Electric Commission's (T&TEC's) establishment of a gas fired power generation plant in Penal. Gas supply was from Amoco's associated oil fields and was negotiated by the Government on behalf of T&TEC. At the time, gas had little value and was flared or reinjected as IOCs focused on crude oil production which could be sold into the global market at higher prices. Arguably, this is still true today.

Following large discoveries of natural gas off the coast of Trinidad, the National Gas Company (NGC) was established in 1975 as a 100% Government owned entity. The NGC was tasked with the promotion of natural gas centred development and was given the monopoly over the purchasing, selling and distribution of natural gas to industrial and commercial consumers in Trinidad and Tobago.

NGC began by entering contracts to purchase natural gas from oil producers (who at the time viewed natural gas as a "by product or 'nuisance child' of the oil industry").[1] NGC concurrently entered into contracts guaranteeing supply to prospective investors. This mechanism created a market for natural gas, thereby encouraging upstream firms to expand supply to spur industrial growth.

NGC also took on the operation and maintenance of the existing 44mile 16inch T&TEC pipeline between Penal and Port of Spain. In order to ensure there was infrastructure to support this new trade in natural gas the NGC constructed one onshore pipeline and one marine pipeline between 1976 and 1978. By 1978 the NGC had 4 large customers and 18 smaller light industrial consumers, and total gas sales of 150MMscf/day.[2]

One of NGC's most defining creations was the Flare Gas Conservation project, which delivered its cheapest source of gas. In 1979 over 180 MMscf of gas was being flared per day in the marine fields off the south east coast of Trinidad. NGC designed and constructed two offshore compression facilities to harvest and compress the gas. This gas was then transported to land for use in power generation and industry.[3]

Following NGC's success at trading and transporting natural gas, it made investments in a natural gas liquids processing plant and in Trintomar, the country's pioneer marine gas production company. In 1992, NGC merged with the National Energy Company, formed in 1979 to develop and maintain Port Point Lisas and promote gas-based industrial development. The NEC also owned the methanol and urea plants at Point Lisas. After the merger, NEC became the Business Development Group within NGC, bringing on board project evaluation and development skills. This led to the development of LNG projects and the La Brea Industrial Estate. By 1997, the NGC had 100 customers; 17 major and 83 small, and it has currently evolved into a large group of companies in the gas sector.

The Government also adopted a strategic partnering strategy in which it invited top-ranked players in various industries to develop projects in Trinidad and Tobago with state participation. In 1975, the Government in partnership with WR Grace began construction of an ammonia plant. The Government also established the Iron and Steel Company of Trinidad and Tobago (Iscott) and contracted for the construction of a direct reduced iron (DRI) steel unit. In 1976, the Government entered into a joint venture with Amoco to establish a fertilizer plant and also began feasibility studies on an aluminium plant, an LNG terminal and a methanol production facility.

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[1] NGC, *History*, (2014), http://ngc.co.tt/about/history/
[2] NGC, *The NGC Story*, (2014), http://ngc.co.tt/about/history/the-ngc-story/
[3] Ibid.

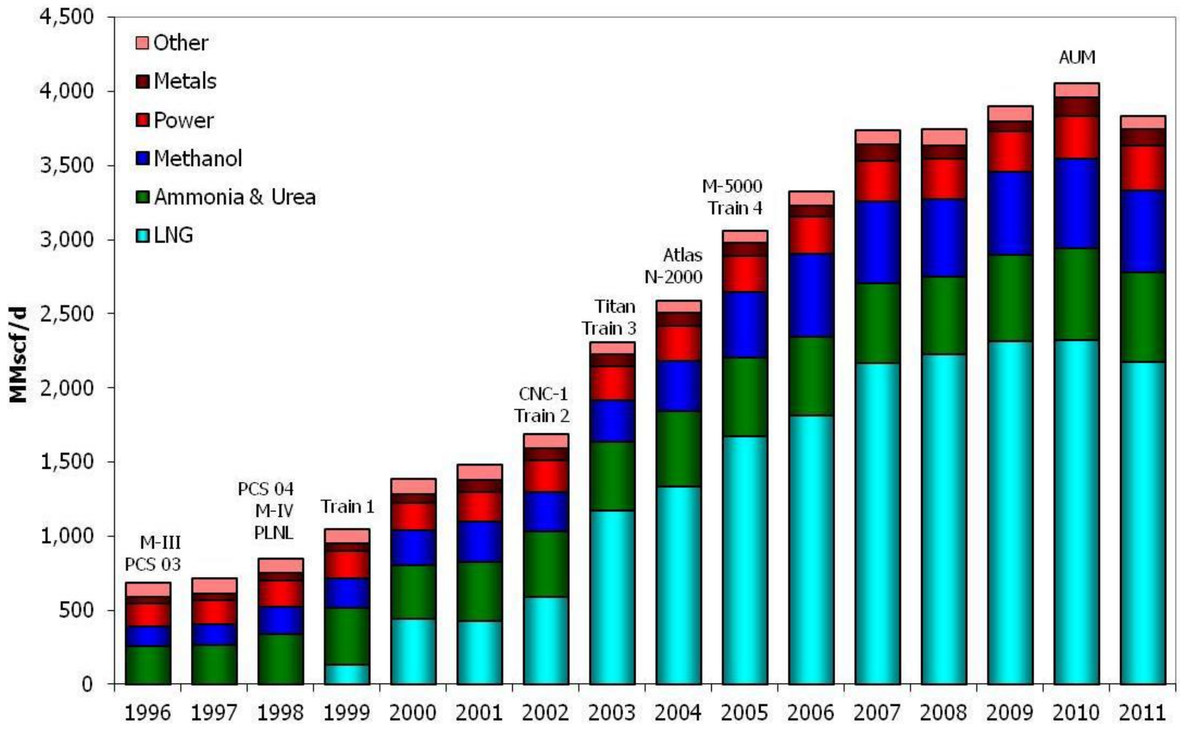
To support these investments the Government also embarked on developing roads, power generation (via T&TEC) and port facilities. The Government's focus on methanol and ammonia production was at a time when demand was rapidly growing for these commodities. It was still early days for the LNG industry and the first LNG plant was commissioned in 1999 – more than 15 years after the development of large ammonia and methanol export projects. However, the LNG projects encouraged more exploration which in turn led to more gas being supplied domestically – for ammonia and methanol production – as other domestic demand had already been saturated.

| **Project Timeline:** |
|---|
| 1953: Natural gas used for power generation in Penal (5 MW) |
| 1954: Natural gas used in cement manufacturing |
| 1955: 5MW addition to Penal power station |
| 1957: 20 MW addition to Penal power station |
| 1959: Gas first used by Federation Chemicals (WR Grace) as feedstock for ammonia. |
| 1960: 20 MW addition to Penal power station |
| 1962: 20 MW addition to Penal power station bringing its total capacity to 70MW |
| 1965: Port of Spain power plant commissioned- 100MW capacity |
| 1968: Amoco discovers large reserves of natural gas off East Coast |
| 1974: two 80 MW units added to Port of Spain power plant raising capacity to 260MW |
| 1975: "Best Uses of Natural Gas Resources" conference held |
| 1975- Startup of Point Lisas; establishment of NGC; formation of Coordinating Task Force (CTF) |
| 1976: Construction of 24" cross country pipeline |
| 1976: Penal power station capacity increased by 40MW to 110 MW |
| 1977: Point Lisas power station commissioned with 88MW capacity |
| 1977: Start up TRINGEN 1. |
| 1978: 40MW addition to Point Lisas power station |
| 1979: Formation of NEC to assume duties of CTF. |
| 1980: ISCOTT established. |
| 1980-1982: Three 88MW units and four 62.5MW units added to the Point Lisas power station bringing its total capacity to 642MW. |
| 1981: Offshore platforms start up; FERTRIN. |
| 1982: Construction of 30-in line |
| 1982-1985: 196MW addition to Penal power station |
| 1983: NGC –Amoco Gas Supply Contract _Cassia Field |
| 1984 : TTMC and TTUC |
| 1984: Two 24MW units added to Port of Spain power station |
| 1988: Tringen 2; NGC invests in Trintomar |
| 1990: NGC to Point Lisas |
| 1991: PPGPL start-up; New gas supply Contract with Amoco. |
| 1992: NGC/NEC merger |
| 1991: Commencement of Production at Trintomar. |

| |
|---|
| 1992-94: State Divestments: Fertrin; TTMC; Urea;T&TEC |
| 1992: New pricing regime introduced: LNG discussions commence; |
| 1993: New supply contracts: BG /Texaco and EOG (then Enron) |
| 1993-1998: Several new players: CMC; PCS Nitrogen; Farmland MissChem; Ispat; Nucor; Cliffs |
| 1997: New Amoco supply contract ; Direct sales to ALNG |
| 1999: ALNG First shipment |
| 2000: Agreement reached on expansion of ANLG Train 2 and 3. |
| 2000: BP takeover of Amoco |
| 2000-2004: Further downstream expansion ALNG Train 2 and 3 Ammonia: Caribbean Nitrogen 1 and 2 Methanol : TTMC 4 ; M5000; Atlas and Titan (Methanex) |
| 2005: Completion of 56 inch pipeline |
| 2006: ALNG Train 4 |
| 2007: Two 105 MW units added to Point Lisas power station |
| 2008: Union Industrial Estate (new gas supply agreements) |
| 2010: AUM complex - first major secondary downstream plant |
| 2011: Completion of NEO, UIE and Tobago pipelines |
| 2013: NGC buys out Conoco's share of PPGPL |

*Timeline Source: Powergen & NG*

*Figure L - 4: Trinidad and Tobago Growth in Natural Gas Utilisation*



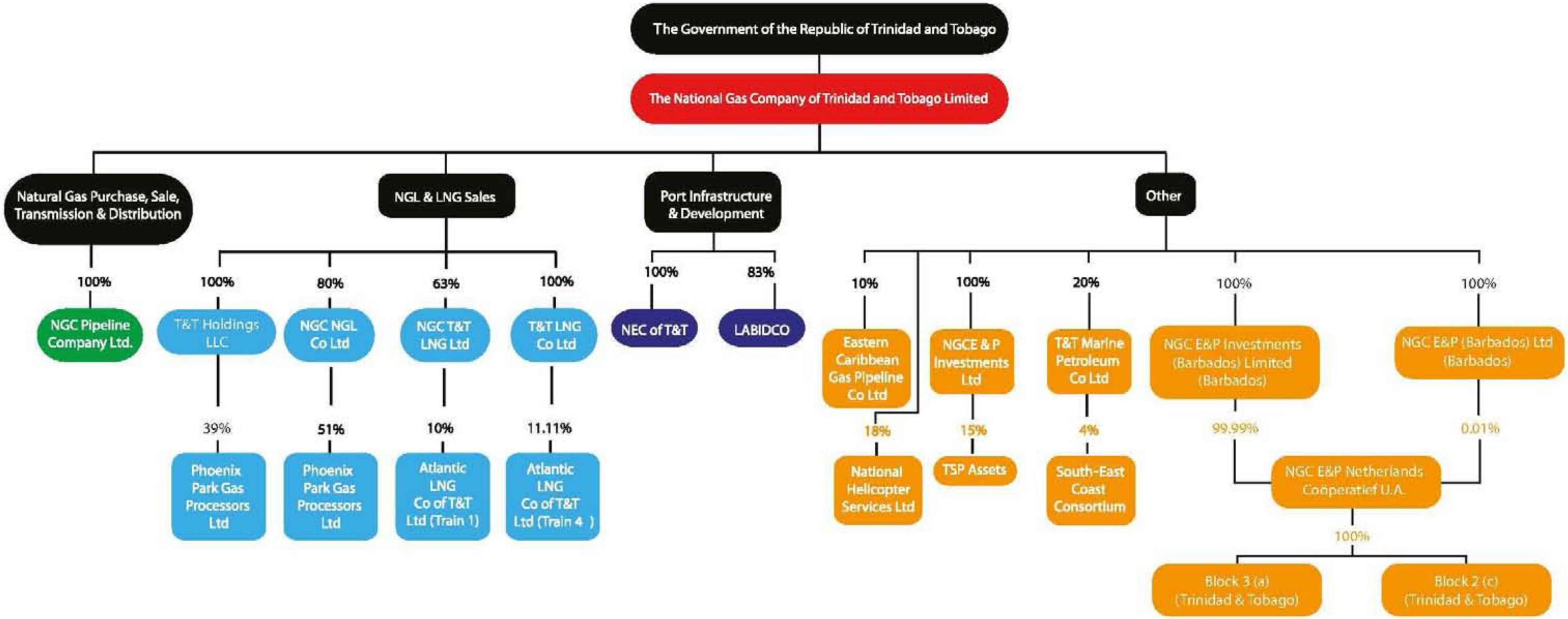

*Source: NGC*

Many of these projects were developed on the Point Lisas Industrial estate which was established in 1966 with Government participation, creating a hub which spurred further industrial development. Point Lisas has attracted over US $ 5 billion of investment in gas based plants alone over the last thirty years.[1] Port Point Lisas, Trinidad and Tobago's second port is also part of the Point Lisas Industrial complex.

In 1980s and 1990s, the Government privatized some gas related state enterprises, with the sale of Iscott to ArcelorMittal in 1989 and T&TEC spinning off its generating assets into Powergen a joint venture between the state and private investors in 1994. In a departure from this policy, Trinidad and Tobago's Government has recently sought to grow its involvement in the gas sector with NGC acquiring Total S.A's upstream assets in Trinidad and Tobago in 2013, and increasing its stake by 39% in Phoenix Park Gas Processors in a US $ 600 million transaction in the same year.[2] Phoenix Park Gas Processors is one of the largest gas processing facilities in North and South America. The NGC currently owns and operates Trinidad's gas distribution system including 1,000km of onshore and marine pipeline. The state continues to be an influential player in the oil & gas, and related industries with six wholly owned, one majority owned, one minority owned and 14 indirectly owned enterprises as of 2013.[3]

[1] Plipdeco.com, *Point Lisas Industrial Port Development Corporation – Overview*, (2014), http://www.plipdeco.com/main/index.php?page=estate-management-overview
[2] Energy.gov.tt, *The Energy Platform*, (2014), http://www.energy.gov.tt/wp-content/uploads/2014/02/Energy-Platform3_2014_FINAL_ALL.pdf
[3] Ministry of Energy and Energy Affairs, *Freedom of Information 2013 Statement*, (2014), http://www.energy.gov.tt/wp-content/uploads/2014/01/Freedom_of_Information_2013_Statement.pdf

*Figure L - 5: Trinidad and Tobago Government Ownership in the Natural Gas sub-sector*




*Source: National Gas Company*

## Industry Structure and Market Regulation

Natural gas pricing is regulated. The Government subsidises the price at which NGC (the gas marketing monopoly) supplies downstream industries like power generation.[1] The NGC uses a cost plus pricing formula to set the price at which it purchases gas, and a formula based on netback to determine the price at which it supplies gas to downstream industries. This netback formula takes into account the prevailing prices of substitute fuels/feedstocks. The rapid development and global competitiveness of Trinidad and Tobago's downstream gas based industry is in part due to the development of a system which delivers low input (feedstock and power) prices to downstream export industries. Despite maintaining subsidies to date, in 1992, the Government began a series of economic reforms including lifting of import restrictions, privatisation, and floating the currency. These policies have led to the growth of foreign direct investment. Under the Petroleum Act the President has pre-emptive rights over all petroleum, petroleum products and petrochemicals produced by a licensee if Trinidad and Tobago is at war, or if the President decrees an emergency. Under the Act the President may also direct a manufacturer to produce specific products and quantities, and to deliver products to a specific location within Trinidad and Tobago for the duration of the decreed emergency. Under such conditions the fair market price at the time and place of delivery is to be paid and the licensee is entitled to compensation for any damage or loss incurred as a result of the Government taking control of its plant or premises during the decreed emergency. Such compensation is to be fixed by agreement between the parties or through arbitration if no agreement is reached.

### Industry Players

In 2010, LNG for export accounted for 58% of natural gas use, domestic ammonia and methanol production accounted for 15% and 14% respectively. Power generation accounted for 7% of gas use. NGC remains the largest player in the downstream market.[2] In addition to the NGC, some of the other players in the gas downstream sector are:

Atlantic LNG- In July 1995, the Atlantic LNG Company of Trinidad and Tobago was formed by subsidiaries of BG group, Repsol, Amoco (now BP), Cabot (now GDF Suez) and NGC to develop natural gas liquefaction operations. It currently has four liquefaction trains. Each train is separately owned but jointly operated allowing economies of scale. The Government has a 10% share in Train 1 and an 11% share in Train 4. Total capacity is 15 million tonnes per annum. At commissioning Train 4 was the largest capacity liquefaction train.[3] A key competitive advantage for Atlantic LNG is that their trains cost less to build than what competitors are now spending to develop new trains in the United States.[4]

Point Lisas- As of 2014, there are a total of 94 companies on 860 hectares within the Point Lisas Industrial Estate comprising power generation facilities, iron and steel, methanol and ammonia production plants.

Powergen- A spinoff of T&TEC, which now owns 51% of the company. Powergen owns and operates three natural gas fired power stations at Port-of-Spain (308 megawatts), Point Lisas (852 megawatts), and Penal (236 megawatts) totaling 1386 megawatts.

Petrochemical manufacturers- Trinidad has a total of 11 ammonia plants of which 7 are on the Point Lisas Industrial Estate. The largest players are Tringen, a joint venture between the Government and Yara International, Caribbean Nitrogen Company (a consortium of international firms) and Potash Corp of Canada which also manufactures urea in Trinidad.[5]

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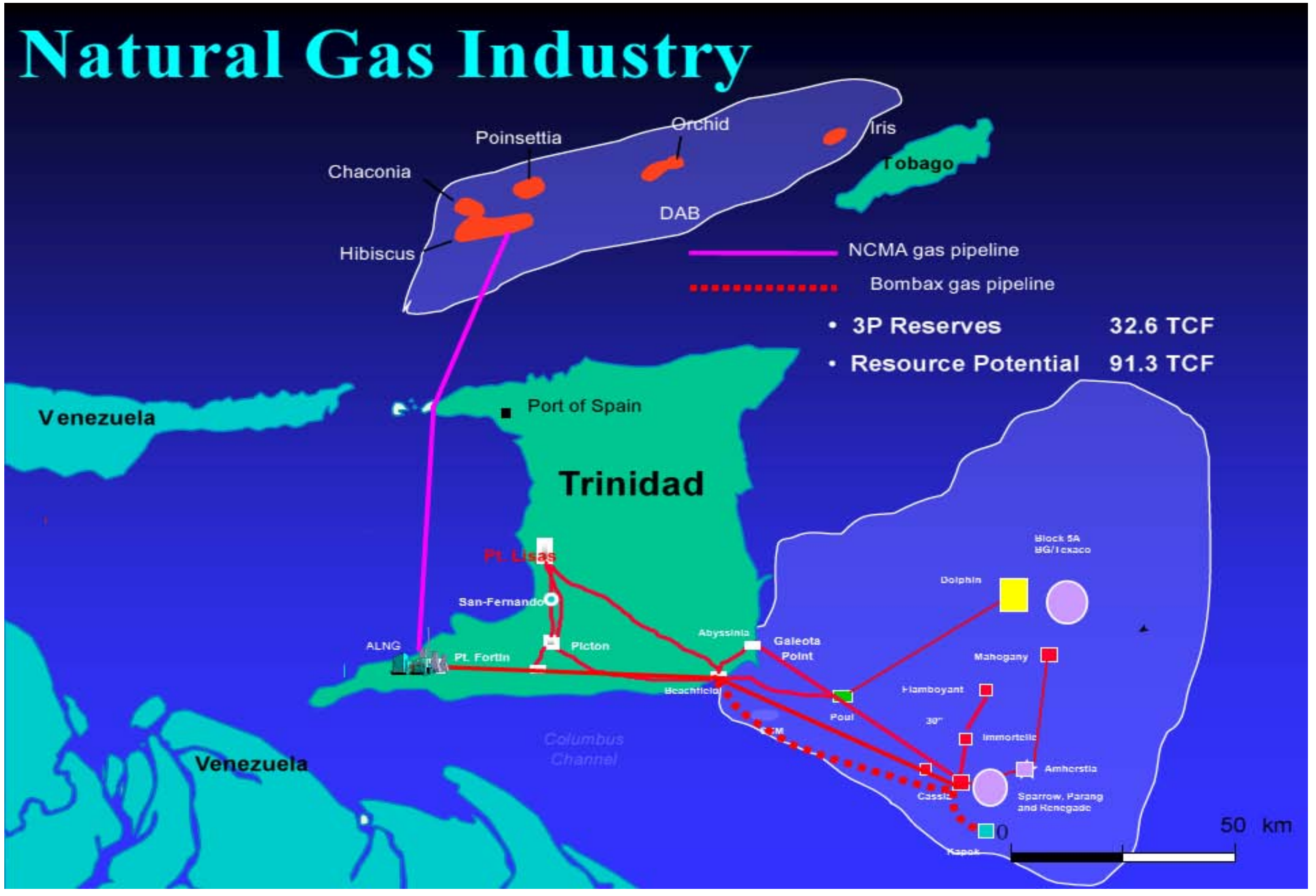
[1] A. Khan, Finance Minister: Hospitals, higher salaries with gas subsidy removal, *Guardian*, (2012), http://www.guardian.co.tt/budget-2013/2012-10-04/finance-minister-hospitals-higher-salaries-gas-subsidy-removal
[2] V. Mercer-Blackman,*Tax Regimes in Hydrocarbon-Rich Countries: How does Trinidad compare?*, University of The West indies, (2014), http://sta.uwi.edu/conferences/12/revenue/documents/Tax_regimes_in_hydrocarbon-rich_countries-MercerBlackman.pdf
[3] Atlanticlng.com, *History*, (2014) http://www.atlanticlng.com/about-us/history
[4] E. Pickrell, Trinidad energy minister touts 'world's first natural gas economy', *Fuel Fix*, (2013), http://fuelfix.com/blog/2013/11/03/trinidad-energy-minister-touts-worlds-first-natural-gas-economy/
[5] U.S. Energy Information Administration, *Country Analysis Note*, (2013), http://www.eia.gov/countries/country-data.cfm?fips=TD

*Figure L - 6: Trinidad and Tobago Location of Industry and Infrastructure vis-à-vis Resources*

(Note: Point Lisas' central location along the coastline)




*Source: University of the West Indies*

## Summary of Observations

Creation of a natural gas focused national oil company should be considered to help develop the gas sector value chain. A key catalyst of Trinidad and Tobago's gas sector growth was the establishing of the NGC which had both the mandate and resources to drive the sector's development. Kenya could establish a company to negotiate contracts for gas supply with oil & gas companies and downstream consumers as well as invest in the required infrastructure like pipelines, processing facilities and storage. Such a mechanism would allow Kenya to guarantee gas supply to potential investors, and possibly participate in investments to the sector.

Developing large industries and power plants has enabled the development of smaller industries in Trinidad and Tobago. As articulated by former Prime Minister Eric Williams, Trinidad and Tobago avoided the easier route of exporting unprocessed resources and instead accepted "…the challenge of entering the world of steel, aluminium, methanol, fertilizer, petrochemicals, in spite of their smallness and in spite of their existing level of technology." Detailed cost-benefit analyses on subsidising natural gas prices should be undertaken to determine whether the value of these downstream industries to society outweighs the cost of subsidies in the long run. Feasibility studies on which of these export oriented industries Kenya can successfully compete globally will also be required. Demand for power generation in Kenya is considerably higher than in Trinidad and expected to grow significantly. Depending on amount of gas reserves, most gas supply may be required for the power sector, with limited opportunities for export processed resources.

Trinidad and Tobago adopted natural gas as a replacement for diesel powered plants. The use of natural gas to generate power is a viable option to lower the cost of power, and replace diesel (heavy fuel oil) powered plants in Kenya. Manufacturing is one of the growth sectors identified under Kenya's Vision 2030 economic pillar. Lowering the cost of power would spur new investment and raise the global competitiveness of Kenyan manufacturers.

Trinidad and Tobago, unlike Kenya, had an established oil industry with revenues that could support the large investments in state owned natural gas processing and distribution industries, as well as supporting infrastructure like ports and roads. Kenya may have to consider a variety of alternative capital sources including public private partnerships (PPPs) to develop the required infrastructure. In terms of financing the industries, Kenya should consider inviting top ranked players to compete for opportunities as Trinidad and Tobago did. Kenya has an emerging industrial and financial sector with regional reach. The Government could consider policy to encourage local participation in the gas sector via joint ventures with these successful Kenyan corporates. Following the example of Atlantic LNG, multiple Kenyan and international companies can partner to own and operate assets jointly to achieve economies of scale and competitiveness. The Government could implement a structure to incentivise such partnering and joint ventures through tax credits for example.

Policy for the development of human capital in the natural gas and petrochemical sectors should also be created. While Trinidad and Tobago had the benefit of some existing talent from the oil sector and early fertilizer industry, Kenya may require a more aggressive approach. By combining the requisite human capital with supporting infrastructure and an emerging industrial and financial sector, Kenya may be able to transform herself into a preferred destination for gas and petrochemical investment.

# Israel

## Sector Overview

The Israel natural gas sector is a relatively young industry, with first gas only arriving in 2004 from the shallow water ‘Mari B’ and ‘Noa’ developments followed by imported pipeline gas from Egypt in 2008. The energy mix of Israel has subsequently undergone a considerable change by the ingress of natural gas with the development of the offshore 'Tamar' gas field in 2013 and the prospect of further volumes from the additional discovery at 'Leviathan', which is considered as one of largest deep-water discoveries of gas worldwide' within the last decade. Israel also has the ability to imported LNG through a SBM system developed in 2012 in response to the curtailment of pipeline supplies from Egypt.

Natural gas has now become a primary source of energy, particularly in the power generation sector through Israel Electric Corporation and also in IPPs and large industrial plants. Spurred by the increase in domestic gas production, the consumption of natural gas has grown steadily from 1.2 BCM in 2004 to 7.8 BCM in 2013. Of this, the power sector accounts for 81% of the total natural gas consumption. The estimates suggest that natural gas demand will rise further to over 20 BCM by 2032.

To meet the growing demand, the high pressure gas transmission network – originally set out in a Gas Master Plan by the Dutch gas company Gasunie in the late 1990’s – has been extended and low pressure distribution networks are being developed to ensure delivery of gas to the consumers.

## Regulatory Structure

The primary Government Ministry responsible for the midstream and downstream sector in Israel is the Ministry of Energy & Water Resources (formerly the Ministry of National Infrastructure). Other Governmental institutions with an interest in the oil & gas industry in Israel are as follows:-

1) The Ministry of Environmental Protection
2) The Israel Antitrust Authority
3) The Israel Securities Authority
4) The Ministry of Finance
5) The Ministry of Interior - plays a role in terms of planning/zoning development for natural gas infrastructure projects, as well as public concerns related to this
6) Public Utility Authority - Electricity

The primary legislation governing the natural gas sector is Natural Gas Sector Law (2002) as update, and under which the industry regulator – Natural Gas Authority (NGA) – operates. The NGA’s role includes the issuing of operating licenses, including the Gas Transmission License awarded to state-owned Israel Natural Gas Lines Limited (INGL).

An Inter-Ministerial Committee was formed on October 2, 2011 to examine the Government policy on the natural gas industry in Israel. This was instigated following the attacks on the gas pipeline from Egypt and the discovery of further indigenous gas supplies offshore Israel, heightening concerns over energy security and the need to coordinate onshore and offshore networks. On August 29, 2012, the Committee submitted its report to the Prime Minister and to the Minister of Energy and Water Resources, for approval. With regards to development of gas transmission and distribution infrastructure, the report called for Government involvement in the planning and construction of natural gas infrastructures (Government will build onshore terminals and plan the offshore gas pipeline network to link fields to shore terminals). Specifically on gas transmission and distribution infrastructure, the report states the following:-

*“**Policy proposed for Government intervention in planning and setting up infrastructure in the natural gas market** – In order to supply natural gas in a reliable and consistent manner to the Israeli energy market in the long-term, central planning of offshore and onshore infrastructure is required, in order*

*to ensure efficient utilization of resources, removal of barriers to competition in order to ensure efficient utilization of resources, increased redundancy and the creation of suitable conditions for rapid development of fields and their connection to the shore. In this context, consideration must be given to economies of scale in these infrastructures and to the location of facilities in relation to the transmission system, the geographic distribution of the demand sources, and limiting the dependence of consumers in the north and center of the country on the southern systems located in the south, as is the situation at present.*

*The Committee recommends that the Government of Israel act, either directly by way of the Ministry of Energy and Water Resources and other relevant ministries, or through Government owned companies with regard to the segment of the natural gas transmission and processing infrastructures within the territorial waters of the State of Israel in the following manner:-*

- *As a rule, the planning, allocation and construction, as necessary, of onshore infrastructure and infrastructure in the territorial waters of the State of Israel designated for the natural gas market, will be carried out with Government intervention and in accordance with laws and plans, particularly National Master Plan 37 H (which in Israel is referred to as "the Land Lord System"). At the time of the planning and allocation of land, inter alia, considerations of increasing system redundancy, competition, and the number of suppliers to the Israeli natural gas market will be taken into account.*
- *In addition, the Government will take steps, insofar as possible, to make statutory arrangements for these infrastructures in order to curtail, to the extent possible, the duration required for such proceedings.*
- *The Ministry of Energy and Water Resources, in coordination with other relevant ministries, will examine the various alternatives for Government intervention in developing infrastructures for the transmission and treatment of natural gas with the aim of ensuring access to the Israeli market by allocating available land for receiving the gas, or by any other means that will ensure that these infrastructures will not be an obstacle preventing the fields from entering the market. In order to create certainty for future fields and to incentivize them, it is proposed that the conclusions of the examination and the recommendations derived therefrom will be presented to the Government no later than the end of June 2013. As stated above, the examination will be made in light of various considerations, among other things, increased redundancy, competition, the diversity of suppliers in the Israeli natural gas economy, and the speed at which the fields can be connected to the infrastructures.*
- *Without derogating from the aforesaid, lease holders who intend to set up an offshore transmission pipeline in the exclusive economic zone would be required to invite other developers to participate in the transmission infrastructure, insofar as possible, in accordance with the regulations set forth, similar to that which has been done in other markets."*

## Ownership

### Midstream – Gas Transportation

INGL is a Government owned company, established in order to develop, construct, operate and maintain the natural gas delivery infrastructure in Israel. The Government granted license granted to the company for 30 years (until 2034) to construct and operate the high pressure delivery system. The natural gas transmission system is composed of four segments: offshore segment, central segment, southern segment and northern segment.

INGL complies with and operates in accordance with the licenses granted by the Ministry of Energy and Water Resources, the bylaws outlined in the Natural Gas Sector Law, and is subject to the decisions of the NGA. INGL is also subject to commercial and safety regulation by the NGA.

The initial investments of INGL were financed with equity provided by the State of Israel, and underpinned by long term transportation agreements signed with the state-owned power generation company Israel Electricity Company (IEC). Additional financing is raised as needed via the capital markets.

All pipelines in Israel are set up on the basis of facilitating third party access, in accordance with the provisions of the Natural Gas Law. One of the main objectives of the Commission was to ensure that the approach applied to INGL and its (mainly) onshore pipeline network would also apply to offshore pipelines that may be developed by producers in the future.

## Infrastructure – Gas

### <u>Midstream - Gas Pipelines</u>

Following the gas discoveries, main natural gas delivery lines were laid in the country. The National Transmission Network of INGL currently includes four main trunklines serving the western, central, northern and southern regions of Israel. The details are provided in Table below:

| Trunkline | Total Length | Flow Routes | Date of Activation |
|---|---|---|---|
| **Offshore** | 98 KM | Ashdod-Tel Aviv-Dor (Inc. 8 Km pipeline to the LNG terminal – Jan. 2013) | May 2006 |
| **Central** | 94 KM | Ashdod-Sorek-kiryat Gat-Ashkelon, Sorek-Nesher | May 2007 |
| **Southern** | 135 KM | Kiryat Gat-Ramat Hovav-Dimona-Rotem-Sdom | November 2009 |
| **Northern** | 84 KM | Dor-Elyakim-Tel Kashish-Haifa, Tel kashish – Alon Tavor | July 2007 – Dor- Elyakim<br>April 2011 – Elyakim-Tel Kashish-Haifa, Tel kashish – Alon Tavor |

The network includes four major components:

1. Receiving terminals, where the suppliers deliver the natural gas
2. Land-based and sub-sea pipelines
3. Pressure Reduction and Metering Systems (PRMS)
4. Block valve stations

The details are provided in the table below:-

| Type of facility | In Operation | In preparation stage |
|---|---|---|
| **Receiving terminals** | 3 (Ashdod, Ashkelon, Hadera LNG terminal) | |
| **Transmission lines** | 443 km | 3 – For Distribution Networks |
| **PRMS** | 23 | |
| **Block valve stations** | 35 | |

Whilst the Master Plan envisaged two pipelines linking the south and north of the country – one onshore and one offshore – the timing and sizing of each of these was flexible so as to allow early gas development through the offshore pipeline (which would experience less planning and way leave delays than the onshore route) with the onshore link being constructed later.

In January 2013, INGL launched the Hadera Deep-water LNG Terminal to receive natural gas from LNG tankers. The decision to build the terminal was made by the Minister of Energy and Water Resources in the middle of 2011, in order to find a way to bridge a temporary undersupply of natural gas created by the gap between the depletion of existing reservoirs, coupled with the cessation of gas supply from Egypt, and the arrival of gas from the Tamar field.

According to the existing plans for network development, the transmission network will be able to transmit between 10 and 15 BCM of natural gas (from the receiving terminals to the customers) per year, and approximately 1.8 MCM/hour. As per the development plans, by 2016, INGL will have extended the transmission network by approximately 274 km, requiring an investment of approximately NIS 3.2 billion. This will enable the company to respond to the increasing demand for natural gas as a primary energy source.

It should be noted that whilst the location, direction and size of gas supplies coming into the Israeli gas network has changed over the years, the basis of the Gas Master Plan that was developed at the outset has generally held firm with only minor amendments required. This is because the rationale for the layout of the system was dictated by an understanding where the primary demand centres for gas were located and allowed for flexibility as to where supplies might enter.

INGL is also responsible for connecting new customers to the national natural gas transmission network. The process requires company authorization, in which the following aspects are considered:-

- **Customer Profile** – INGL gathers initial information about the customer’s profile and needs, to make sure these meet the conditions set in the licensing agreement.
- **Assessment** – Assessment of the project’s feasibility in terms of engineering requirements and the profitability of investing in network expansion.
- **Company Approval** – A detailed report of the profiling and feasibility findings is submitted to the company’s investment committee for approval. The investment committee is authorized to give final approval prior to the expansion of the network and the connection to new clients or sites.

The transmission fee for natural gas transmission is supervised by the NGA, and is determined according to the capacity rates and the cost of service rate. Shippers pay a transmission tariff composed of a capacity fee and a throughput fee, and a connection fee for the construction of a PRMS. The users of the transmission system (Shippers) include IEC and large industry plants, as well as the Gas Distribution Companies. The Transmission Tariff is comprised of 90% Capacity Tariff and 10% Throughput Tariff. The components of the total charges payable by Shippers are as follows:-

- Connection Fees - a payment for connecting to the transmission system and the PRMS (paid once).
- Capacity Tariff - a fixed payment based the maximum capacity required by each client (paid monthly).
- Throughput Tariff - a variable payment based on actual gas consumption of each client (paid monthly).

The Capacity Tariff is set by the Natural Gas Authority Committee and is intended to cover company expenses. Currently, two thirds of the rate is linked to CPI and one third to the U.S. dollar. In addition to the transmission fee, the natural gas customer bears the following additional expenses:

- The cost of the gas itself as determined by the supplier (an unregulated rate);
- The local distributor’s fee, regulated by the NGA, is based on the distribution area and the customer’s market share in conjunction with the costs tendered by the successful bidder in the local gas distribution tenders;
- The fee for connecting to the local distribution network – a one-time fee for the physical connection to the pipelines through which the low-pressured gas is transmitted to the customer’s facilities. This supervised fee is based on the customer’s market share and consumption rates.

For those large consumers connected direct to the high pressure transmission network, no distribution costs are incurred.

The delivery rate is uniform for all consumers and the consumer bears the cost of connection to the delivery system. Until now, gas has mainly replaced coal, oil, and diesel at power stations and industrial plants, including Israel Chemicals, Dead Sea Works, Nesher Paper Works, and Delek Desalination. In 2011, power stations accounted for 82% of total gas consumption in Israel, and industry consumed 18%.

The country has also witnessed developments in exports. In January 2014, Israel signed its first natural gas export deal through which the Palestinian Power Generation Company (PPGC), the Palestinian Authority's electric utility company, will purchase $1.2 billion worth of Israeli natural gas over a 20-year period. The gas will be shipped to a $300 million power plant that PPGC plans to build in the West Bank city of Jenin. The gas sales are scheduled to commence in 2016 or 2017 when the Leviathan field is expected to begin producing gas for the Israel system.

In February 2014, Israeli signed a contract with Jordan through which Israel will sell $500 million worth of natural gas to Jordan over 15 years. The gas will be obtained from the Tamar field. The sales are scheduled to begin in 2016 upon the completion of preliminary pipeline infrastructure connecting Jordan to the INGL system.

There is also speculation as to further, more substantial exports of natural gas from Leviathan. Proposed plans have included LNG export via Cyprus (Greenfield project) or via Egypt (connecting to the existing LNBG liquefaction plants that are short of feedstock gas supply), or an undersea pipeline to Turkey.

## Summary of Observations

### Flexibility in the Master Plan

The basis of the existing network remains the same as when the original Gas Master Plan was developed in the late 1990's, before the identity of the gas pipeline network developer/owner was known and before the confirmed discovery of economic quantities of indigenous gas reserves. The plan was developed with a good understanding of where natural gas was likely to be needed from a demand perspective, which would be largely driven by the requirements for power generation at least during the early years. The network outline then included a number of contingent options that allowed for the fact that gas supply may enter the system at a number of locations, either in the south or the north of the country.

In addition, it was recognized that pipeline developments were often held up by consents and way leave issues and local protests. Therefore, laying part of the transmission system just off the coast facilitated a more rapid transition to gas usage. Kenya may have a similar opportunity to fast-track certain sections of the proposed gas pipeline network by laying just offshore, enabling offshore fields and/or LNG imports to enter the onshore system at different locations.

### Open Access

The Government was clear from the outset that the gas industry should work as far as possible on a competitive basis, and it understood that this required access to the infrastructure for delivering gas to consumers. INGL is the high pressure system operator and effectively has a monopoly position for the onshore/near offshore network. However, its operating license restricts its participation in the buying and selling of gas (other than for system balancing purposes), so it is not in a position to distort the working of the market. Kenya must consider whether it wants a state-owned entity to perform a similar role regarding the development and operation of the national network.

### Power Demand Driven

Although this was a Greenfield gas industry, the Government had a clear picture of the likely demand centres because it would be based primarily on proposed gas-fired power generation projects, either repowering existing oil-fired plant or planned CCGT's. After the system was developed to reach these power plant locations, it was a relatively low cost and fast implementation process to then connect industrial consumers followed by smaller consumers via gas distribution franchises. We might anticipate that the early years of the Kenyan gas market would follow a similar pattern, with power generation projects driving initial demand and influencing the rate and direction of pipeline system development.

**Pricing**

The flip-side of the open access policy of the Government was that potential consumers would be exposed to market prices. The regulator was required to set tariffs for the use of the pipeline systems on the basis of a utility returns on investment, but the gas itself was the subject of commercial negotiations between buyers and sellers. The lack of price subsidies elsewhere in the energy sector meant that the true relative economics were able to prevail, which in turn led to the drive from consumers for access to gas supply as it was not only environmentally advantageous compared to oil products but also cheaper in most instances. Kenyan regulations should ensure access to gas infrastructure by third parties and avoid price subsidies so as to encourage the robust development of the sector and continued investment along the gas value chain.

**Security of Supply**

Although Israel may be considered a risk in terms of terrorist activity affecting the gas pipeline network, in reality this has not been the case for the national system which has enjoyed a strong track record of continual supply. The main incident incurred in the importing pipeline system from Egypt and therefore outside the control of INGL. This led to the development of an alternative supply – LNG via a SBM – and to the development of additional storage and flexibility within the combined onshore and offshore systems to allow for possible supply interruptions in the future. In the same way, Kenya should consider the development of gas infrastructure in an integrated manner so as to enhance security of supply.

# Appendix M. - Glossary

| Abbreviation | Description |
|---|---|
| **b** | Billion |
| **bbl** | barrels |
| **Bcm** | Billion cubic meters /year |
| **Billion bbl** | Billion barrels |
| **Bn bbl** | Billion barrels |
| **bpd** | barrels per day |
| **BPO** | Business Process Outsourcing |
| **Capex** | Capital Expenditure |
| **CBA** | Cost Benefit Analyses |
| **CCGT** | Combined Cycle Gas Turbine |
| **CIA** | Central Intelligence Agency |
| **CNG** | Compressed Natural Gas |
| **CPI** | Consumer Price Index |
| **CSE** | Compulsory Stock Entity |
| **CSR** | Corporate Social Responsibility |
| **cUS$** | United States cents |
| **DFI** | Development Finance Institution |
| **DOSHS** | Directorate of Occupational Safety and Health Services |
| **DPK** | Dual Purpose Kerosene |
| **DRSRS** | Department of Resource Surveys and Remote Sensing, Ministry of Environment, Water and Natural Resources |
| **DTA** | Double taxation treaties |
| **EA** | Environmental Audits |
| **EAC** | East African Community |
| **EDL** | Effluent Discharge Licence |
| **EHS** | Environmental, Health and Safety |
| **EIA** | Energy Information Administration |
| **EIA** | Environmental Impact Assessment |
| **EIA/EA** | Environment (Impact Assessment and Audit) |
| **EITI** | Extractive Industries Transparency Initiative |
| **EMCA** | Environmental Management and Coordination Act |
| **EMP** | Environmental Management Plan |
| **EMS** | Energy Management Systems |
| **ERC** | Energy Regulatory Commission |
| **ESIA** | Environmental and Social Impact Assessment |
| **ESMP** | Environmental and Social Management Plan |
| **FDI** | Foreign Direct Investment |
| **FS** | Financial Statements |
| **FSRU** | Floating Storage and Regasification Unit |

| Abbreviation | Description |
|---|---|
| **GDC** | Geothermal Development Company |
| **GDP** | Gross Domestic Product |
| **GHG** | Greenhouse Gas |
| **GoK** | Government of Kenya |
| **GTL** | Gas-To-Liquids |
| **HGV** | Heavy Goods Vehicle |
| **HSF** | Heritage And Stabilization Fund |
| **HSFO** | High Sulphur Fuel Oil |
| **ICT** | Information and Communications Technology |
| **IEA** | International Energy Agency |
| **IMF** | International Monetary Fund |
| **IOC** | International Oil Company |
| **IRR** | Internal Rate of Return |
| **JV** | Joint Ventures |
| **k** | thousand |
| **KEBS** | Kenya Bureau of Standards |
| **KenGen** | Kenya Electricity Generating Company Ltd |
| **KEPTAP** | Kenya Petroleum Sector Technical Assistance Project |
| **KES** | Kenya Shillings |
| **KFS** | Kenya Forest Service |
| **km** | kilometres |
| **KMA** | Kenya Maritime Authority |
| **KMFRI** | Kenya Marine and Fishery Research Institute, |
| **KOGA** | Kenya Oil and Gas Association |
| **KOSF** | Kipevu Oil Storage Facility |
| **KOT** | Kipevu Oil Terminal |
| **KPA** | Kenya Port Authority |
| **KPC** | Kenya Pipeline Company |
| **KPRL** | Kenya Petroleum Refineries Limited |
| **KRA** | Kenya Revenue Authority |
| **kWh** | Kilowatt hour |
| **KWS** | Kenya Wildlife Service |
| **LAPSSET** | Lamu Port and South Sudan Ethiopia Transport project |
| **LCDA** | LAPSSET Corridor Development Authority |
| **LCPDP** | Least Cost Power Development Plan |
| **LNG** | Liquefied Natural Gas |
| **LNGC** | LNG Carrier |
| **LPG** | Liquefied Petroleum Gas |
| **m** | Million |
| **$m^3$** | cubic metres |
| **MDP** | Ministry of Devolution and Planning |
| **MEP** | Ministry of Energy and Petroleum |

| Abbreviation | Description |
|---|---|
| **MMBtu** | Million British thermal units |
| **MMSCMD** | Million Metric Standard Cubic Meter per Day |
| **MoE** | Ministry of Education |
| **MoEP** | Ministry of Energy and Petroleum |
| **MoF** | Ministry of Finance |
| **MoIED** | Ministry of Industrialization and Enterprise Development |
| **MT** | Metric Tonnes |
| **MTP** | Medium Term Plans |
| **MWh** | Megawatt hours |
| **NAFFAC** | National Fossil Fuels Advisory Committee |
| **NAPIMS** | National Petroleum Investments Management Services |
| **NCAC** | National Coal Advisory Committee |
| **NDOC** | Kenya National Disaster Operations Centre |
| **NEMA** | National Environmental Management Authority |
| **NGC** | National Gas Company |
| **NGOs** | Non-Governmental Organizations |
| **NH3** | Ammonia |
| **NOC** | National Oil Company |
| **NOCK** | National Oil Corporation of Kenya |
| **NPV** | Net Present Value |
| **NT** | The National Treasury |
| **NTBA** | Non-time Based Assumptions |
| **NUPAC** | National Upstream Petroleum Advisory Committee |
| **OECD** | Organization for Economic Co-operation and Development |
| **OMC** | Oil Marketing Company |
| **OPEC** | Organization of the Petroleum Exporting Countries |
| **Opex** | Operating Expenditure |
| **OSHA** | The Occupational Safety and Health Act, 2007 |
| **OSMAG** | Oil Spill Mutual Aid Group |
| **p.a.** | per annum |
| **PAP** | Project Affected People |
| **PETRONAS** | Petroliam Nasional Berhad |
| **PIEA** | Petroleum Institute of East Africa |
| **PMP** | Petroleum Master Plan |
| **PMS** | Premium Motor Spirit |
| **Ppm** | parts per million |
| **PPP** | Public Private Partnership |
| **PSC** | Production Sharing Contract |
| **REA** | Rural Electrification Authority |
| **ROR** | Rate Of Return |
| **SBM** | Single Buoy Mooring |
| **SCM** | Standard Cubic Meter |

| Abbreviation | Description |
|---|---|
| **SEA** | Strategic Environmental Assessment |
| **SESA** | Strategic Environmental and Social Assessment |
| **SIA** | Social Impact Assessment |
| **SLECC** | Sheng Li Engineering & Construction Company |
| **SOT** | Shimanzi Oil Terminal |
| **SPR** | Strategic Petroleum Reserves |
| **sq. km** | Square Kilometre |
| **SWF** | Sovereign Wealth Fund |
| **t** | Tonnes |
| **TBA** | Time Based Assumptions |
| **Tcf** | Trillion cubic feet |
| **Tcm** | Trillion cubic metres |
| **TOR** | Terms of Reference |
| **TVET** | Technical and Vocational Education Training |
| **UNCTAD** | United Nations Conference on Trade and Development |
| **UPA** | Upstream Petroleum Authority |
| **UPRA** | Upstream Petroleum Regulatory Authority |
| **US$** | United States Dollars |
| **WACC** | Weighted Average Cost of Capital |
| **WARMA** | Water Resources Management Authority |

*Please note: Reference to Kenya Shillings (KES) has been made at a translation into US dollars at [US$ 1 = KES 89.16]. (http://www.oanda.com/currency/converter/, 1 December 2014.*